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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, 2002

Commission file number 1-8246

Southwestern Energy Company

(Exact name of Registrant as specified in its charter)

Arkansas

(State or other jurisdiction of
incorporation or organization)

71-0205415

(I.R.S. Employer
Identification No.)

2350 North Sam Houston Parkway East, Suite 300, Houston, Texas 77032

(Address of principal executive offices, including 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 \$0.10	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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 an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes No

The number of shares outstanding as of February 13, 2003, of the Registrant's Common Stock, par value \$0.10, was 25,980,378. The aggregate market value of the voting stock held by non-affiliates of the Registrant was \$289,713,706 based on the New York Stock Exchange - Composite Transactions closing price on February 13, 2003, of \$11.40. For purposes of this calculation, the Registrant has assumed that its directors and executive officers are affiliates.

Document incorporated by reference: Portions of the Registrant's Definitive Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 14, 2003 are incorporated by reference into Part III of this Form 10-K.

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CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF K&A ENERGY CONSULTANTS, INC.

**SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
for fiscal year ended December31, 2002**

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This Annual Report on Form10-K includes certain statements that may be deemed to be “forward-looking” within the meaning of Section27A of the Securities Act of 1933 and Section21E of the Securities Exchange Act of 1934. We refer you to “Risk Factors” in Item1 of Part I and to “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item7 of Part II of this Form10-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 Form10-K, along with other information about us and our operations, financial information, other documents filed with the Securities and Exchange Commission, or the SEC, and other useful information about us can found on our website at <http://www.swn.com>.

PART I

ITEM 1. BUSINESS

Overview

Southwestern Energy Company is an independent energy company primarily focused on the exploration for and production of natural gas. We were originally organized in 1929 in Arkansas as a local gas distribution company. Today, we are an exempt holding company under the Public Utility Holding Company Act of 1935, conduct our primary activities through four wholly-owned subsidiaries and derive the vast majority of our operating income and cash flow from our natural gas and oil exploration and production, or EP, business. In February 2001, we relocated our corporate headquarters from Fayetteville, Arkansas to Houston, Texas. All of our operations are located within the United States. We operate principally in three segments:

1Exploration and Production – Our primary business is natural gas and crude oil exploration, development and production, with our operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We engage in natural gas and oil exploration and production through our wholly-owned subsidiaries, SEECO, Inc., Southwestern Energy Production Company, (which we refer to as SEPCO), and Diamond “M” Production Company. SEECO operates exclusively in Arkansas, holds a large base of both developed and undeveloped gas reserves and conducts an ongoing drilling program in the historically productive Arkansas part of the Arkoma Basin. SEPCO conducts development drilling and exploration programs in the Oklahoma portion of the Arkoma Basin, the Permian Basin of Texas and New Mexico, and in Louisiana and East Texas. Diamond “M” operates properties in the Permian Basin of Texas. A wholly-owned subsidiary of SEPCO, Overton Partners, L.L.C., owns an interest in Overton Partners, L.P., a limited partnership formed in 2001 to drill and complete 14 development wells in SEPCO’s Overton Field properties in East Texas.

2Natural Gas Distribution – We are also engaged in the gathering, distribution and transmission of natural gas. Our wholly-owned subsidiary Arkansas Western Gas Company, which we refer to as Arkansas Western, operates integrated natural gas distribution systems in northern Arkansas serving approximately 140,000 retail customers. Arkansas Western is the largest single purchaser of SEECO’s gas production.

3Marketing, Transportation and Other – As a complement to our other businesses, we provide marketing and transportation services in our core areas of operation. Our gas marketing subsidiary, Southwestern Energy Services Company, was formed in 1996 to better enable us to capture downstream opportunities which arise through marketing and transportation activity. We also hold a 25% general partnership interest in the NOARK Limited Partnership, which we refer to as NOARK, which owns the Ozark Pipeline, a 749-mile interstate pipeline with a total throughput capacity of 330 MMcf per day, along with related gathering systems. We also own an interest in approximately 150 acres of real estate, most of which is undeveloped and located in Fayetteville, Arkansas.

Our Business Strategy

Our business strategy is focused on providing long-term growth in the net asset value of our business. We prepare economic analyses for each of our drilling and acquisition opportunities 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. We target adding \$1.30 to \$1.50 of discounted pre-tax PVI for each dollar we invest. For example, the average economics for the wells we drilled at the Overton Field in 2002, based on current expected costs and production and assuming an average NYMEX price of \$4.00 per Mcf of gas and \$25.00 per barrel of oil, would result in an estimated discounted pre-tax PVI of \$1.90 for every dollar invested. This would result in an approximate pre-tax rate of return of 35%. We are also focused on creating and capturing additional value beyond the wellhead through our natural gas distribution, marketing and transportation businesses.

For our EP business, the key elements of our business strategy are:

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- *Continue to Exploit and Develop Existing Asset Base* . We seek to maximize the value of our existing asset base by developing and exploiting our properties that have substantial production and reserve growth potential while also controlling per unit production costs. We intend to add proved reserves and increase production through the use of advanced technologies, including detailed technical analysis of our properties, and by drilling infill locations and selectively recompleting existing wells. We also plan to drill step-out wells to expand known field limits.
- *Grow Through Exploration* . We conduct an active exploration program that is designed to complement our lower risk exploitation and development drilling efforts with moderate to high risk exploration projects that have greater reserve potential. We employ a rigorous prospect selection process utilizing state-of-the-art computer-aided exploration technology to analyze and interpret geological and geophysical data, including a large inventory of 3-D seismic data. We intend to manage our exploration expenditures through the optimal scheduling of our drilling program and by selectively reducing our participation in certain exploratory prospects through promoted sales of interests to industry partners.
- *Rationalize Our Property Portfolio* . We actively pursue opportunities to reduce production costs of our properties. We continually seek to rationalize our portfolio of EP assets by selling marginal properties in an effort to reduce production costs and improve overall return.
- *Pursue Strategic Acquisitions* . We selectively review opportunities to acquire producing properties and leasehold acreage, focusing in particular on the regions where we have existing operations. In addition, we seek to acquire operational control of properties that we believe have significant exploration and exploitation potential.

Recent Development

Sale of Our Mid-Continent Properties . In November 2002, we sold our remaining non-strategic Mid-Continent properties, including our properties in the Sho-Vel-Tum area in southern Oklahoma, the Anadarko Basin in western Oklahoma and the Sooner Trend in northwestern Oklahoma, for a total of \$26.4 million. These properties represented approximately 32.9 Bcfe of reserves and produced approximately 2.5 Bcfe annually. We expect this divestiture to result in a decrease in our future average production costs per unit of production. We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — Exploration and Production — Operating Costs and Expenses.”

Exploration and Production

In 1943, we commenced a program of exploration for and development of natural gas reserves in Arkansas for supply to our utility customers. In 1971, we initiated an EP program outside Arkansas, unrelated to the utility’s requirements. Since that time, our EP activities outside Arkansas have expanded substantially. In 1998, we brought in a new executive management team for our EP business which has implemented a number of initiatives to refocus our EP business. These efforts have included a recruiting campaign to improve our technical professional staff which has resulted in a change in that staff of more than 75%. Our explorationists now have an average of over 20years of experience and have a proven track record of finding natural gas and oil during their careers. The operations of our EP business were reorganized into asset management teams based on the geographic location of our exploration and development projects. In addition, a new incentive compensation plan, which includes stock based awards, was established to more closely align our employees efforts with the interests of our shareholders.

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Areas of Operation

We operate our EP business in four regions—Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. Operating income for our EP business was \$36.0million and EBITDA was \$83.1million in 2002. Our operating income and EBITDA declined in 2002 from \$69.3million and \$115.0million, respectively, in 2001, primarily because lower realized natural gas and oil prices decreased our revenues while our operating expenses slightly increased. We refer you to “Business—Other Items—Reconciliation of Non-GAAP Measures” in Item1 of Part I of this Form10-K for a table that reconciles EBITDA with our operating income as derived from our audited financial information.

As of December31, 2002, our estimated proved natural gas and oil reserves were 415.3 Bcfe and had a pre-tax PV-10 value of \$694.1million. Approximately 90% of our proved reserves were natural gas and 77% were classified as proved developed. We operate approximately 74% of our reserves, based on our pre-tax PV-10 value, and our average proved reserves-to-production ratio, or average reserve life, approximated 10.4years at year-end 2002. Revenues of our EP subsidiaries are predominantly generated from production of natural gas. Sales of natural gas production accounted for 88% of total operating revenues for this segment in 2002, 89% in 2001, and 82% in 2000.

In 2002, we replaced 209% of our production volumes by adding an estimated 83.7 Bcfe of proved natural gas and oil reserves at a finding and development cost of \$1.02 per Mcfe, excluding reserve revisions. Our finding and development cost including the effect of upward reserve revisions due to higher year-end commodity prices was \$0.99 per Mcfe in 2002. For the three years ended December31, 2002, we achieved an average reserve replacement ratio of 210% and an average finding and development cost of \$1.04 per Mcfe, excluding reserve revisions. Including reserve revisions, these three-year averages were 193% and \$1.13 per Mcfe, respectively.

Our portfolio includes low-risk development drilling in the Arkoma Basin and East Texas, moderate-risk exploration and exploitation properties in the Permian Basin, and higher risk, greater-potential exploration opportunities in the onshore Gulf Coast region. The following table provides information as of December31, 2002 related to proved reserves, well count, and net acreage, and 2002 annual information as to production and capital expenditures, for each of our core operating areas and overall:

	Arkoma	East Texas	Permian	Gulf Coast	Total
Estimated Proved Reserves:					
Total Reserves (Bcfe)	188.7	111.0	57.1	58.5	415.3
Percent of Total	45%	27%	14%	14%	100%
Percent Natural Gas	100%	95%	52%	86%	90%
Percent Proved Developed	84%	65%	83%	74%	77%
Production (Bcfe)	19.8	5.9	6.9 ⁽¹⁾	7.5	40.1
Capital Expenditures (millions)	\$18.2	\$33.6	\$5.4	\$28.0	\$85.2
Total Gross Wells	813	49	386	79	1,327
Total Net Acreage	263,112	16,117	39,425	82,770	401,424
Net Undeveloped Acreage	99,341	5,529	22,391	57,962	185,223
Pre-tax PV-10:					
Amount (millions)	\$ 329.1	\$ 151.9	\$ 90.2	\$ 122.9	\$ 694.1
Percent of Total	47%	22%	13%	18%	100%
Percent Operated	79%	96%	38%	54%	74%

(1)Includes 2.0 Bcfe of production related to the Mid-Continent properties sold during 2002.

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Arkoma Basin. The Arkoma Basin provides a solid foundation for our EP program and represents a significant source of our production and reserves. At December 31, 2002, we had approximately 188.7 Bcf of natural gas reserves in the Arkoma Basin, representing approximately 45% of our total reserves. During 2002, we participated in 25 wells and 41 workovers which added 18.3 Bcf of gas reserves at a finding and development cost of \$0.99 per Mcf. Our gas production in the Arkoma Basin was 19.8 Bcf during 2002, or 54.2 MMcf per day.

Our activities in the Arkoma Basin continue to generate a significant amount of our cash flow. With three-year average finding and development costs of \$1.08 per Mcf and three-year average production, or lifting, costs of \$0.30 per Mcf (including production taxes), our cash margins in the Arkoma Basin are very attractive. Lifting costs continued to be low during 2002 at \$0.36 per Mcf (including production taxes). Including the impact of commodity hedges, we realized 83% of the average price we received for natural gas from the Arkoma Basin, after direct general and administrative expenses and cash expenses.

We have traditionally operated in a portion of the Arkoma Basin that is primarily within the boundaries of our utility gathering system in Arkansas which we refer to as the “fairway.” Our strategy in the fairway is to delineate new geologic prospects and extend previously identified trends using our extensive database of regional structural and stratigraphic maps. In 2002, we completed 8 wells out of 11 drilled in the fairway and those wells added 3.9 Bcf of new natural gas reserves. An especially encouraging prospect among the fairway wells is the Grimmer #1-17 well, which is located in Johnson County, Arkansas and, as of April 2002, tested at a rate of 10.7 MMcf per day from Hale perforations at 4,100 feet. Our average working interest in the 2002 fairway wells is 67% and our average net revenue interest is 58%. We intend to drill up to 15 wells in the fairway portion of the Arkoma Basin in 2003.

In recent years, we have extended our development program into the Oklahoma portion of the Arkoma Basin, and have also tested new exploration plays to continue its growth. In 2002, we continued the development of our Ranger Anticline prospect area, located at the southern edge of the Arkansas portion of the basin. An example of our continued successful development of this complex overthrust play is the Brasher #1-11 well that was drilled and put into production in August 2002 at a rate of 12.0 MMcf per day from Lower Borum sands at approximately 5,500 feet and 6,750 feet. We have begun testing new exploration prospect areas on the southern edge of the Arkoma Basin similar to our Ranger Anticline play.

Additionally in 2002, we accelerated our extensive workover program in the Arkoma Basin which includes fracture stimulations, artificial lift, recompletion and wellbore repair projects, and this acceleration has provided meaningful production increases. We performed 41 of these workover projects in 2002, resulting in net production increases totaling 6.9 MMcf per day at a total net cost of \$3.9 million. One workover project, the Currier #1-35 well in Franklin County, Arkansas, was recompleted to the Sells zone and stimulated in the Casey sand. This work increased gross production from the well by 850 Mcf per day and resulted in a net reserve addition of 1.1 Bcf.

Our strategy for the Arkoma Basin is to continue our development drilling and workover programs at a level that maintains our production and reserve base. In 2003, we plan to invest approximately \$22.6 million in the Arkoma Basin to drill approximately 30 wells and perform approximately 60 workover projects. We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures” for a discussion of our planned capital expenditures for 2003.

East Texas. The Overton Field in Smith County, Texas provides us with a low-risk, multi-year drilling program with significant production and reserve growth potential based on the level of infill drilling that is possible in the field over the next several years. Our interest in the Overton Field (which now totals approximately 16,500 gross acres) was originally acquired in April 2000 and 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. We expect to receive regulatory approval to allow downspacing of our properties in the Overton Field to 80-acre spacing, which will provide us with an extensive inventory of additional drilling locations. Our average working interest in the Overton Field is 97% and our average net revenue interest is 79%.

We expanded our position in the area during 2001 through a farm-in of approximately 5,800 adjacent acres. This acreage, which we call “South Overton,” contains nine 640-acre units, most of which have only been drilled to 320-acre spacing. The farm-in agreement requires us to drill a minimum of one well per 120 days on this acreage in 2003. Our current net revenue interest in South Overton is 73%.

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In 2001, SEPCO formed a limited partnership with an investor to drill and complete 14 development wells in the Overton Field. All 14 development wells have been completed and we have no continuing obligations to drill additional wells. Because SEPCO is the sole general partner and owns a majority interest in the partnership, operating and financial results for the partnership are consolidated with our other operations and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. During 2002 and 2001, the minority interest owner in the partnership contributed \$0.5million and \$13.5million, respectively, in capital to the limited partnership. The investor's share of 2002 and 2001 revenues, less operating costs and expenses, was \$1.5million and \$0.9million, respectively.

We continue to pursue potential acquisitions in the Overton Field area and during 2002 we acquired 3,300 net acres of land offsetting recent Travis Peak and Cotton Valley development in Anderson County, Texas. While undeveloped at this time, we see the potential to apply technologies we refined in the Overton Field to this acreage block, which is located approximately 55 miles southwest of the Overton Field.

In 2002, we drilled a total of 15 wells at the Overton Field and three wells at South Overton. All 18 wells were successful. To date, we have drilled a total of 33 wells in the area with a 100% success rate. Daily gross production at the Overton Field has increased from 2.0 MMcfe in March 2001 to approximately 27.0 MMcfe at year-end 2002 resulting in net production of 5.9 Bcfe during 2002. Our average production costs (including production taxes) decreased to \$0.40 per Mcfe in 2002 from \$0.70 per Mcfe in 2001, and that unit rate could decline further as production from the field increases.

Our proved reserves at the Overton Field increased to 111.0 Bcfe at year-end 2002, or 27% of our total reserves. We invested approximately \$33.6 million at the Overton Field during 2002 which resulted in proved reserve additions of 56.4 Bcfe with a finding and development cost of \$0.60 per Mcfe compared to a finding and development cost of \$0.82 per Mcfe at the Overton Field in 2001.

Continued downspacing should allow us to drill an additional 100 wells in the area over the next two years. This should achieve 80-acre spacing in the majority of the higher potential areas. Our results at the Overton Field over the past two years have been significant and we believe that the acceleration of the field's development will provide substantial growth in production and reserves over the next few years. We intend to invest approximately \$78.0 million in East Texas during 2003, which includes drilling up to 47 new wells using four rigs at the Overton Field. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures" for a discussion of our planned capital expenditures in 2003.

Permian Basin. At December 31, 2002, our proved reserves in the Permian Basin were 57.1 Bcfe, or 14% of our total reserves. Our production in the basin during 2002 was 4.9 Bcfe, or 13.4 MMcfe per day, and our production costs (including production taxes) averaged \$1.13 per Mcfe. During 2002, our capital expenditures totaled \$5.0 million, resulting in reserve additions of 1.4 Bcfe. Excluding reserve revisions, our three-year average finding and development cost in the basin was \$2.23 per Mcfe and three-year average reserve replacement ratio was 85% for the period ended December 31, 2002.

While our overall results in the basin were disappointing in 2002, we have recently experienced some encouraging results from drilling horizontal wells targeting the Cherry Canyon sand formation. The Peregrine #1 well located in Eddy County, New Mexico, was drilled and completed in 2002 in the Cherry Canyon horizon at 4,850 feet, with a 1,390-foot horizontal lateral. We estimate that the well exposed 720 feet of well-developed pay. We operate this well with a 100% working interest. This well is currently producing approximately 90 barrels of oil per day and we expect to drill up to three more horizontal wells in this area in 2003.

We de-emphasized our drilling activities in the Permian Basin in 2002 and will continue to do so in 2003. In 2003, we plan to invest approximately \$4.8 million in the Permian Basin, to drill up to nine wells. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures" for a discussion of our planned capital expenditures in 2003.

Gulf Coast. Our Gulf Coast operations are located in the onshore areas of Texas and Louisiana. Our proved reserves in these areas totaled 58.5 Bcfe at December 31, 2002, or 14% of our total revenues. Approximately 29.8 Bcfe of our proved reserves in the Gulf Coast was located in Louisiana. Average net daily production in the Gulf Coast area was 20.5 MMcfe and production costs (including production taxes) averaged \$1.07 per Mcfe during 2002. We invested \$28.0million in the area in 2002 and added 7.6 Bcfe of proved reserves. Of the \$28.0million in capital investments, approximately \$5.8million was invested in leasehold and seismic for future prospect development. Excluding reserve revisions, our three-year average finding and development cost in the Gulf Coast region was \$1.83 per Mcfe and three-year reserve replacement ratio was 246% for the period ending December 31, 2002. Including revisions, these three-year averages were \$2.13 per Mcfe and 212%.

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South Louisiana continues to be the main focus area of our exploration activities in the Gulf Coast. Since our first discovery in December 1999, the efforts of our exploration program have resulted in eight successful wells out of the last 18 drilled in South Louisiana. In 2002, we participated in eight wells, of which two were successful. During 2002, we were also active in acquiring seismic data to facilitate future exploration in the area. We completed our 135-square mile Duck Lake 3-D seismic project located in St. Martin and St. Mary Parishes and are currently interpreting that data for prospects to be drilled later in 2003 and beyond. We are the operator of this project, and hold a 50% working interest. Additionally, we completed a transaction late in 2002 with a major seismic data vendor for a license to approximately 1,033 square miles of 3-D seismic data in other prospective areas in the southern half of Louisiana. Our current 3-D database in South Louisiana now includes over 2,700 square miles, has the potential to generate a significant inventory of exploration prospects and leads. For 2003, we plan to invest approximately \$21.7million in the Gulf Coast region and drill up to eight exploration wells. We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures” for a discussion of our planned capital expenditures in 2003.

Acquisitions

In 2002, we purchased 6.6 Bcfe of proved reserves for direct costs of \$3.1million, at an average cost of \$0.47 per Mcfe. The largest single transaction was the acquisition of a minority interest in the Susser #2 well located in Nueces County, Texas for \$1.7million. We are the operator of the well. The remaining \$1.2million was spent to acquire additional working interests in the Overton Field and in several Arkoma Basin wells.

In 2001, we purchased proved reserves of 4.5 Bcfe for direct costs of \$6.5 million, or \$1.46 per Mcfe. The purchase included overriding royalty interests in the Arkoma Basin of 2.2 Bcfe, and additional working interests in the Overton Field of 1.9 Bcfe.

In April 2000, we purchased our initial interest in the Overton Field in Smith County, Texas, from Total Fina Elf for direct costs of \$6.1million. Proved developed producing reserves associated with the purchase were 7.5 Bcfe, for a purchase price per Mcfe of \$0.81. The purchase included 16 active gas wells in 13 spacing units, 8,800 contiguous acres in established units and 2,000 additional undeveloped acres outside those units.

In 1999, we purchased producing properties in the Permian Basin with estimated proved reserves of 9.4 Bcf of natural gas and 576 MBbls of oil, or 12.9 Bcfe. The properties were purchased from Petro-Quest Exploration, a privately held company headquartered in Midland, Texas, for direct costs of \$9.4million. We did not make any producing property acquisitions in 1998.

As part of our current business strategy, we selectively review opportunities to acquire producing properties and leasehold acreage, focusing in particular on the regions where we have existing operations. In addition, we seek to acquire operational control of properties we believe have significant exploitation and exploration potential.

Capital Expenditures

We invested a total of \$85.2million in our EP program and participated in drilling 65 wells during 2002. Of these drilled wells, 45 were successful, 16 were dry and 4 were still in progress at year-end. Our investments were balanced between our core areas of operations, with approximately \$18.2million invested in the Arkoma Basin, \$33.6million in East Texas, \$5.4million in the Permian Basin and Mid-Continent areas, and \$28.0million in the Gulf Coast. Of the \$85.2million invested, approximately \$15.5million was invested in exploratory drilling, \$46.1million in development drilling and workovers, \$9.1million for land and leasehold acquisition and seismic expenditures, \$3.1million for producing property acquisitions, and \$11.4million in capitalized interest and expenses and other technology-related expenditures.

In 2003, our planned EP capital budget is \$137.1million, with approximately 83% allocated to drilling. The majority of our investments in 2003 will be directed to the lower-risk part of our EP portfolio, primarily due to our planned acceleration of the development of the Overton Field in East Texas. In 2003, approximately 73% of our capital will be allocated to lower-risk development drilling activities in the Arkoma Basin (\$22.6million) and East Texas (\$78.0million). The remainder of our capital will be allocated to medium-risk exploration and exploitation in the Permian Basin (\$4.8 million), higher risk exploration in South Louisiana (\$21.7million) and capital investments in other frontier areas (\$10.0million). Of the \$137.1 million capital budget, approximately \$16.1million will be invested in exploratory drilling,

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\$97.2million in development drilling and workovers, \$12.0million for land and leasehold acquisition and seismic expenditures, and \$11.8million in capitalized interest and expenses 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 Expenditures” for a discussion of our planned capital expenditures in 2003.

Sales and Major Customers

Our daily natural gas equivalent production averaged 109.8 MMcfe in 2002, compared to 109.0 MMcfe in 2001 and 97.7 MMcfe in 2000. Our natural gas production was 36.0 Bcf in 2002, compared to 35.5 Bcf in 2001 and 31.6 Bcf in 2000. We also produced 682,000 barrels of oil in 2002, compared to 719,000 barrels of oil in 2001 and 676,000 barrels in 2000. We are targeting production in 2003 to be approximately 42 Bcfe to 44 Bcfe.

We realized an average wellhead price of \$3.00 per Mcf for our natural gas production in 2002, compared to \$3.85 per Mcf in 2001 and \$2.88 per Mcf in 2000, including the effect of hedges. Our hedging activities lowered the average gas price \$0.11 per Mcf in 2002, \$0.31 per Mcf in 2001, and \$1.04 per Mcf in 2000. Our average oil price realized was \$21.02 per barrel in 2002, compared to \$23.55 per barrel in 2001 and \$22.99 per barrel in 2000, including the effect of hedges. Our hedging activities lowered the average oil price \$2.92 in 2002, \$0.03 per barrel in 2001 and \$6.39 per barrel in 2000.

Our gas sales to unaffiliated purchasers were 30.6 Bcf in 2002, compared to 30.4 Bcf in 2001 and 23.8 Bcf in 2000. All of our oil production is sold to unaffiliated purchasers. This gas and oil production is sold under contracts that reflect current short-term prices and which are subject to seasonal price swings. These combined gas and oil sales to unaffiliated purchasers accounted for 85% of total EP revenues in 2002, 83% in 2001 and 76% in 2000.

Our utility subsidiary, Arkansas Western is the largest single customer for sales of our gas production and the only customer that accounted for more than 10% of our natural gas and oil production revenue in 2002. 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” below for further discussion of these contracts. Sales to Arkansas Western accounted for approximately 15% of total EP revenues in 2002, 17% in 2001 and 24% in 2000. SEECO’s sales to Arkansas Western were 5.4 Bcf in 2002, compared to 5.1 Bcf in 2001 and 7.8 Bcf in 2000. The increase in sales in 2002 was primarily caused by increased supply requirements due to colder weather when compared to 2001. Weather in 2002, as measured in degree days, was 8% colder than in 2001 and 2% warmer than normal. The decrease in sales in 2001 was primarily due to warmer weather and the sale of the utility’s Missouri gas distribution properties in May 2000. Weather in 2001, as measured in degree days, was 9% warmer than both normal and the prior year for Arkansas Western’s service territory. SEECO’s gas production provided approximately 37% of the utility’s requirements in 2002, 33% in 2001 and 42% in 2000. 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 Arkansas Western’s distribution system.

Future sales to Arkansas Western’s gas distribution systems will be dependent upon our success in obtaining gas supply contracts with the utility systems. In the future, our subsidiaries will continue to bid to obtain these gas supply contracts, although there is no assurance that they will be successful. If successful, we cannot predict the amount of fixed demand charges, if any, that would be associated with the new contracts. We expect future increases in our gas production to come primarily from sales to unaffiliated purchasers. 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 periodically enter into hedging activities with respect to a portion of our projected natural gas and crude oil production through a variety of financial arrangements intended to support natural gas and oil prices at targeted levels 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, 2002, we had hedges in place on 42.6 Bcf of future gas production and 240,000 barrels of future oil production. Subsequent to December 31, 2002 and prior to February 14, 2003, we hedged 3.0 Bcf of 2003 gas production under costless collars with floor prices of \$4.00 per Mcf and ceiling prices ranging from \$5.85 to \$6.20 per Mcf, and 100,000 barrels of future oil production at \$29.40 per barrel. We currently have hedges in place on approximately 75% of our targeted 2003 gas production and approximately 65% of our 2003 targeted oil production. We refer you to “Quantitative and Qualitative Disclosures About Market Risks,” for further information regarding our hedge position at December 31, 2002.

Disregarding the impact of hedges, we expect the average price received for our gas production to be approximately \$0.10 to \$0.20 per Mcf lower than average spot market prices, as market differentials that reduce the

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average prices received are partially offset by demand charges under the contracts covering our intersegment sales to Arkansas Western. Disregarding the impact of hedges, we expect the average price received for our oil production to be approximately \$1.25 per barrel lower than average spot market prices, as market differentials reduce the average prices received.

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 oil and gas and the securing of the labor and equipment required to conduct 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 has increased in recent years due largely to the development of improved access to interstate pipelines. Due to our significant leasehold acreage position in Arkansas and our long-time presence and reputation in this 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 generally 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.

Oil Price Controls And Transportation Rates

Sales of crude oil, condensate and gas liquids are not currently regulated and are made at negotiated prices. Effective January 1, 1995, the Federal Energy Regulatory Commission (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.

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have 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 FERC. In the past, the federal government has regulated the prices at which gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. 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. Commencing in 1992, the FERC issued Order No.636 and subsequent orders (collectively, "Order No. 636"), which require interstate pipelines to provide transportation separate, 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. The implementation of these orders has not had a material adverse effect on our results of operations. The courts have largely affirmed the significant features of Order No.636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. In 2000, the FERC issued Order No.637 and subsequent 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. Most major aspects of Order No.637 are pending judicial review. We cannot predict whether and to what extent FERC's market reforms will survive judicial review and, if so, whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that we will be affected by any action taken in a materially different way than other natural gas producers and marketers with which we compete. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Natural Gas Distribution

We distribute natural gas to approximately 140,000 customers in northern Arkansas through our subsidiary, Arkansas Western. Our utility continues to capitalize on the healthy economy and sustained customer growth found in its Northwest Arkansas service territory. In April 2001, the U.S. Census Bureau listed Northwest Arkansas as the sixth fastest growing community in the United States. As home to the largest public corporation in the world, Wal-Mart Stores, Inc., the region has experienced significant growth due to its presence in the area. Other large corporations such as Tyson Foods and J.B. Hunt Transportation have also contributed to this area's development. Approximately 86% of Arkansas Western's customers are located in this part of the state and, in recent years, Arkansas Western has experienced customer growth of approximately 2% to 3% annually.

Operating income for our natural gas distribution business was \$7.6 million in 2002, compared to \$10.3million in 2001 and \$12.6million in 2000 (excluding the Missouri utility properties). EBITDA generated by our utility segment was \$14.0million in 2002, compared to \$17.1million in 2001 and \$20.7 million in 2000 (excluding the Missouri utility properties). We refer you to "Business—Other Items—Reconciliation of Non-GAAP Measures" in Item1 of Part I of this Form10-K for a table that reconciles EBITDA with our operating income as derived from our audited financial information. Our operating income and EBITDA decreased primarily due to increased operating costs and expenses and reduced usage per customer brought about by high gas prices. We filed for an \$11.0million annual rate increase with the Arkansas Public Service Commission, or the APSC, in November 2002. The requested increase is the first Arkansas Western has made since 1996. The APSC has ten months to review the filing and reach a decision on the amount of the increase, if any, to be approved, therefore, we expect that any increase granted would be effective during the fall of 2003.

In June 2000, we announced we were pursuing the sale of our utility operations in Arkansas to fund a \$109.3million judgment against us, which we refer to as the Hales judgment. Although we received several serious expressions of interest from bona fide parties, we did not receive an offer that was acceptable to us. We are no longer pursuing a sale of the utility system and intend to operate the Arkansas utility properties as a continuing part of our business.

On May31, 2000, we completed the sale of our Missouri gas distribution assets for \$32.0million. The sale resulted in a pre-tax gain of approximately \$3.2million and proceeds from the sale were used to repay outstanding indebtedness.

Gas Purchases and Supply

Arkansas Western purchases its system gas supply through a competitive bidding process implemented in October 1998, and directly at the wellhead under long-term contracts with flexible pricing provisions. In 2002, SEECO successfully bid on gas supply packages representing approximately two-thirds of the requirements for Arkansas Western for 2003.

Arkansas Western also purchases gas for its system supply 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 5% of the utility's gas purchases are under take-or-pay contracts. Currently, Arkansas Western 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.

Arkansas Western has a regulated 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 purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the level included in the base 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.

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Markets and Customers

Arkansas Western provides natural gas to approximately 123,000 residential, 16,400 commercial, and 200 industrial customers, while also providing gas transportation services to approximately 70 end-use and off-system customers. Total gas throughput in 2002 was 27.3 Bcf, compared to 27.1 Bcf in 2001 and 33.4 Bcf in 2000. The higher volumes in 2002 were due to weather that was 8% colder than in 2001 and an increase in volumes delivered to the utility's end-use transportation customers. The decrease in 2001 resulted from the loss of throughput associated with the sale of the utility's Missouri assets in May 2000 and warmer weather. Off-system transportation volumes were 2.2 Bcf in 2002 and 3.1 Bcf in both 2001 and 2000.

Residential and Commercial. Approximately 87% of the utility's revenues in 2002 were from residential and commercial markets. Residential and commercial customers combined accounted for 56% of total gas throughput for the gas distribution segment in 2002, compared to 54% in 2001 and 55% in 2000. Gas volumes sold to residential customers were 9.0 Bcf in 2002, compared to 8.4 Bcf in 2001 and 10.9 Bcf in 2000. Gas sold to commercial customers totaled 6.2 Bcf in 2002, 6.1 Bcf in 2001 and 7.6 Bcf in 2000. The increases in gas volumes sold in 2002 were due to weather that was 8% colder than in 2001. The decreases in gas volumes sold in 2001 were due to the sale of the Missouri utility properties and warmer weather. Weather during 2001 was 9% warmer than both normal and the prior year.

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 recently as tariffs implemented in Arkansas 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 Arkansas Western's industrial and end-use transportation customers were 9.9 Bcf in 2002, 9.5 Bcf in 2001 and 11.8 Bcf in 2000. The decrease in deliveries in 2001 was primarily due to the sale of the utility's Missouri properties. No industrial customer accounts for more than 9% of Arkansas Western's total throughput. Arkansas Western offers a transportation service that allows larger business customers to obtain their own gas supplies directly from other suppliers. A total of 73 customers are currently using the transportation service.

Competition

Arkansas Western has experienced a general trend in recent years toward lower rates of usage among its customers, largely as a result of conservation efforts that we encourage. We experience increasing competition from alternative fuels such as electricity, fuel oil, and propane. Arkansas Western has historically maintained a substantial price advantage over these fuels for most applications, enabling us to achieve excellent market penetration levels. However, the high gas prices experienced in the 2000–2001 heating season temporarily eroded the price advantage in some markets. Arkansas Western has made progress in regaining price advantage in its markets as gas prices have declined from the levels experienced during the winter of 2000–2001. Arkansas Western also has the ability through its approved tariffs to lower its rates to large customers to be competitive with available alternative fuels or if the threat of bypass exists. This tariff is likely to be eliminated in the pending rate case and replaced with an alternative mechanism that will require APSC approval for rate discounts.

Regulation

Arkansas Western's utility rates and operations are regulated by the APSC. We operate through municipal franchises that are perpetual by virtue of state law. These franchises, however, may not be exclusive within a geographic area. As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation are required to unbundle residential sales services from transportation services in an effort to promote greater competition. Although no such legislation or regulatory directives related to natural gas are presently pending in Arkansas, Arkansas Western is aggressively controlling costs and constantly reviewing issues such as system capacity and reliability, obligation to serve, rate design and stranded or transition costs.

In Arkansas, legislation was adopted in 2001 for the deregulation of the retail sale of electricity between October 2003 and October 2005. In December 2001, the APSC submitted to the legislature its annual report on the development of electric deregulation and recommended that the legislature consider suspending deregulation until 2010 or 2012.

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Furthermore, legislation has been recently introduced seeking to repeal the deregulation of the retail sale of electricity. It is unknown whether additional legislation will be adopted or, if it is adopted, what its final form will be. If electric deregulation occurs in Arkansas, legislative or regulatory precedents may be set that would also affect natural gas utilities in the future. These effects may include further unbundling of services and the regulatory treatment of stranded costs.

In November 2002, Arkansas Western filed a request with the APSC for an adjustment in its rates totaling \$11.0million, or 9.1%, annually. The requested increase is the first Arkansas Western has made since 1996. The APSC has ten months to review the filing and reach a decision. As a result, Arkansas Western expects that any increase granted would be effective in the fall of 2003. Arkansas Western's most recent rate increase was approved in December 1996 for the utility's Northwest region and in December 1997 for its Northeast region. The APSC approved annual rate increases of \$5.1million and \$1.2million, respectively.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the normal purchased gas adjustment clause in the utility's approved tariffs. Arkansas Western had under-recovered purchased gas costs of \$12.9million in its current assets at December 31, 2000. The amount of under-recovered purchased gas costs increased significantly during January 2001 as a result of rapidly increasing gas costs. The temporary tariff allowed the utility accelerated recovery of the gas costs it had incurred during the 2000–2001 winter heating season. In April 2002, Arkansas Western filed a revised purchased gas adjustment clause that provides better matching between the time the gas costs are incurred and the time the costs are recovered. The APSC approved the new clause in May 2002. At December 31, 2001, Arkansas Western had over-recovered purchased gas costs of \$8.2million. At December 31, 2002, Arkansas Western had approximately \$5.7 million of over-recovered purchased gas costs.

In May 1999, the staff of the APSC initiated a proceeding in which it sought an annual reduction of approximately \$2.3million in the rates Arkansas Western charges its customers in Northwest Arkansas. Staff's position was based on various adjustments to the utility's rate base, operating expenses, capital structure and rate of return. A large portion of the proposed reduction was based on a downward adjustment to the utility's current return on equity authorized by the APSC in 1996. During the third quarter of 1999, Arkansas Western reached agreement with the staff and the APSC to resolve this issue and to close several other open dockets. In the settlement agreement, Arkansas Western agreed to reduce its rates collected from customers on a prospective basis in the amount of \$1.4million annually, effective December 1, 1999.

Gas distribution revenues in future years will be impacted by customer growth and rate increases allowed by the APSC. In recent years, Arkansas Western has experienced customer growth of approximately 2% to 3% annually in its Northwest Arkansas service territory, while it has experienced little or no growth in its service territory in Northeast Arkansas. Based on current economic conditions in its service territories, we expect this trend in customer growth to continue.

We refer you to "Risk Factors—We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future" for a discussion of the impact that government regulation has on our natural gas distribution business.

Marketing, Transportation and Other

Operating income from the marketing, transportation and other segment, which includes income from real property held by our subsidiary, A.W. Realty Company, was \$2.9million in 2002, compared to \$3.0million in 2001 and \$2.5 million in 2000. EBITDA for this segment was \$2.8million in 2002, compared with \$2.4million in 2001 and \$3.0million in 2000. We refer you to "Business—Other Items—Reconciliation of Non-GAAP Measures" for a table that reconciles EBITDA with our operating income as derived from our audited financial information.

Gas Marketing

Our gas marketing subsidiary, Southwestern Energy Services Company, was formed in 1996 to better enable us to capture downstream opportunities which arise through marketing and transportation activity. Through utilization of our existing asset base, we are focused on creating and capturing value beyond the wellhead.

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Our current marketing operations primarily relate to the marketing of our own gas production and some third-party natural gas that is primarily sold to industrial customers connected to our gas distribution systems. Our operating income from marketing was \$2.7million on revenues of \$131.1million in 2002, compared to \$2.7million on revenues of \$190.3million in 2001, and \$2.5 million on revenues of \$207.7million in 2000. We marketed 45.5 Bcf of natural gas in 2002, compared to 49.6 Bcf in 2001 and 59.6 Bcf in 2000. In late 2000, we began marketing less third-party natural gas in an effort to reduce our potential credit risk and concentrated more on marketing our affiliated production. Of the total volumes marketed, purchases from our EP subsidiaries accounted for 67% in 2002, 66% in 2001 and 33% in 2000.

Transportation

In January 1998, we entered into an agreement with Enogex Inc., a subsidiary of OGE Energy Corp. (“Enogex”), to expand the NOARK Pipeline and provide access to Oklahoma gas supplies through an integration of NOARK Pipeline with the Ozark Gas Transmission System. Ozark was a 437-mile interstate pipeline system that began in eastern Oklahoma and terminated in eastern Arkansas. Enogex acquired Ozark and contributed the pipeline system to the NOARK partnership. Enogex also acquired the NOARK partnership interests not held by us. On July 1, 1998, the FERC authorized the operation and integration of Ozark and NOARK Pipeline as a single, integrated pipeline. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK Pipeline that resulted in our interest in the partnership decreasing from approximately 48% to 25%, with Enogex owning the remaining 75% interest. There are also provisions in the agreement with Enogex which allow for revenue allocations to us above our 25% partnership interest if certain minimum throughput and revenue assumptions are not met.

The new integrated system, known as Ozark Pipeline, became operational November 1, 1998, and includes 749 miles of pipeline with a total throughput capacity of 330.0 MMcf per day. Deliveries are currently being made by the pipeline to portions of Arkansas Western’s distribution systems and to the interstate pipelines with which it interconnects. The average daily throughput for the pipeline was 168.1 MMcf per day in 2002, compared to 134.1 MMcf per day in 2001 and 188.2 MMcf per day in 2000.

At December 31, 2002, Arkansas Western had transportation contracts with Ozark Pipeline for 66.9 MMcf per day of firm capacity. These contracts expire in 2003 and are renewable annually thereafter until terminated with 180 days’ notice. These contracts are currently being renegotiated. The merged pipeline system now has greater access to major gas producing fields in Oklahoma. We expect that the pipeline’s additional throughput will create new marketing and transportation opportunities for us and reduce the losses NOARK has incurred in the past. The merged pipeline also provides our utility systems with additional access to gas supply. Our share of NOARK’s results of operations were losses of \$0.3million in 2002, \$1.5million in 2001 and \$1.8million in 2000. The improvements in operating results since 2000 result primarily from the ability to collect higher transportation rates on interruptible volumes. We believe that we will be able to continue to reduce the losses we have experienced on the NOARK project and expect our investment in NOARK to be realized over the life of the system.

Other

Our wholly owned subsidiary, A. W. Realty Company, owns an interest in approximately 150 acres of real estate, most of which is undeveloped. A.W. Realty’s real estate development activities are concentrated on a 130-acre tract of land located near a growing part of Fayetteville, Arkansas. A.W. Realty continues to review with a joint venture partner various options for developing this property that would minimize our initial capital expenditures, but still enable us to retain an interest in any appreciation in value.

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 cost and availability of alternative fuels, level of consumer demand, and 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.

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The NOARK Pipeline previously competed with two interstate pipelines, one of which was the Ozark system, to obtain gas supplies for transportation to other markets. The integration with Ozark provides increased supplies to transport to both local markets and markets served by the three major interstate pipelines that Ozark Pipeline connects with in eastern Arkansas. We believe that the Ozark Pipeline will provide the additional gas supplies necessary to compete more effectively for the transportation of natural gas to end-users and markets served by the interstate pipelines.

Regulation

Prior to the integration with Ozark, the operations of NOARK Pipeline were regulated by the APSC. The APSC had established a maximum transportation rate of approximately \$0.285 per dekatherm. The integration of NOARK Pipeline with Ozark resulted in an interstate pipeline system subject to FERC regulations and FERC-approved tariffs. The FERC has set the maximum transportation rate of Ozark Pipeline at \$0.2867 per dekatherm.

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 Form10-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 operating 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 our operating income, as derived from our audited financial information for the years-ended December31, 2002, 2001 and 2000:

	EP	Natural Gas Distribution	Marketing, Transportation and Other	Total
<u>2002</u>				
Operating income	\$ 36,048	\$ 7,563	\$ 2,894	\$ 46,505
Depreciation, depletion and amortization	48,570	6,581	201	55,352
Other income (expense)	(104)	(138)	(324)	(566)
Minority interest	(1,454)	—	—	(1,454)
EBITDA	\$ 83,060	\$ 14,006	\$ 2,771	\$ 99,837
<u>2001</u>				
Operating income	\$ 69,340	\$ 10,346	\$ 2,983	\$ 82,669
Depreciation, depletion and amortization	46,446	6,200	995	53,641
Other income (expense)	180	600	(1,579)	(799)
Minority interest	(930)	—	—	(930)
EBITDA	\$ 115,036	\$ 17,146	\$ 2,399	\$ 134,581
<u>2000</u>				
Operating income (1)	\$ 40,704	\$ 14,655	\$ 2,460	\$ 57,819
Depreciation, depletion and amortization	39,079	6,691	852	46,622
Other income (expense)	(311)	(609)	(292)	(1,212)
Minority interest	—	—	—	—

EBITDA (1)

\$ 79,472

\$ 20,737

\$ 3,020

\$ 103,229

(1) Amounts exclude unusual items of \$109.3million for the Hales judgment and \$2.0million for other litigation.

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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 legislation. These laws and regulations:

- require permits for drilling wells;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

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. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is 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 currently 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

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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, most 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, 2002, we had 522 total employees, including 346 employed by our natural gas utility, of which 30 are represented under a collective bargaining agreement. We believe that our relationships with our employees are good.

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.

We may have difficulty financing our planned 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. In the future, we may require additional financing, in addition to cash generated from our operations, to fund our planned growth. We cannot be certain that 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.

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;

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- 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.

The prices for natural gas and oil could be significantly affected by the prospect and outcome of war in Iraq, for example.

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 effect on us.

A substantial or extended decline in natural gas and oil prices would have a material adverse effect on our financial position, results of operations, access to capital and the quantities of natural gas and oil that may be economically produced. 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 expenditures 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, profitability and liquidity 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%, 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. They also require a write-down if the ceiling limit is exceeded, even if prices declined for only a short period of time.

If natural gas and oil prices fall significantly, 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 shareholders’ equity.

Repercussions from any terrorist act or from armed hostilities in the United States or abroad could harm our revenues, business operations, profitability or growth.

The terrorist attacks that occurred on September 11, 2001 caused significant instability in the world’s markets. There can be no assurance that the armed hostilities will not escalate or that these terrorist attacks, or the United States’ responses to them, will not lead to further acts of

terrorism and civil disturbances in the United States or elsewhere,

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which may further contribute to the economic instability in the United States where we operate. Any armed conflict, civil unrest or additional terrorist activities, and the attendant political instability and societal disruption, could reduce demand for our products or disrupt our ability to conduct our exploration, production, development and marketing activities, which could harm our business.

The natural gas and oil reserves data we report are only estimates and may prove to be inaccurate.

There are numerous uncertainties, including many factors beyond our control inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures. Reserve data represent only estimates. In addition, the estimates of future net cash flows from our proved reserves and their present value are based upon various assumptions about future production levels, prices and costs that may prove to be incorrect over time. Any significant variation from these assumptions could result in the actual quantity of our reserves and future net cash flows being materially different from the estimates. 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, operating and development costs and other factors.

At December 31, 2002, approximately 23% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assume that we can and will make these expenditures and conduct these operations successfully, which may not occur.

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.

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 and production, marketing and transportation 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 laws and regulations, including environmental, health and safety regulation. The natural gas and oil regulatory environment could change in ways that might substantially increase these costs. Regulated matters include permits for exploration, development and production operations, such as permits for discharges of wastewaters and other substances generated in connection with drilling operations, bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning operations, the spacing of wells and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. In addition, at the U.S. federal level, the FERC regulates interstate transportation of natural gas under the NGA. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

As an owner or lessee and operator of natural gas and oil properties, we are subject to various federal, state and local regulations and laws relating to the discharge of substances into, and protection of, the environment. These laws and 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 or laws 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 are 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.

Drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such 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. We rely to a significant extent on seismic data and other advanced technologies in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that 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.

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.

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 expenditure requirements may result in reduction or forfeiture of our interests in some of our non-operated projects.

Other companies 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. 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 will be outside our control, including the operator's expertise and financial resources, approval of other participants in drilling wells and selection 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 expenditures associated with such project. If we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Shortages of oil field 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. 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.

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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 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 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 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 level of indebtedness may adversely affect operations and limit our growth.

The terms of the indenture relating to our outstanding senior notes and our revolving credit facility impose significant 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:

- incurring additional debt, including guarantees of indebtedness;
- paying dividends on stock, redeeming stock or redeeming subordinated debt;
- making investments;
- creating liens on our assets; and
- selling assets.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, 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 the agreements governing our debt 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 repayment of outstanding debt. We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of 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 or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt.

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The terms of our debt, including our credit facility and our indentures, 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.

At December 31, 2002, we had long-term indebtedness of \$342.4 million, excluding \$42.6 million relating to our several guarantee of NOARK's debt obligation. Indebtedness under our revolving credit facility was \$117.4 million of our total long-term indebtedness.

Our hedging activities may prevent us from benefiting from price increases, may reduce our revenues 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. We currently have hedges on approximately 75% of our targeted 2003 natural gas production and approximately 65% of our targeted 2003 oil production. Our hedging activities reduced revenues by \$6.1 million in 2002, \$10.3 million in 2001 and \$39.3 million in 2000. 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.

In addition, future market price volatility could create significant changes to the hedge positions reflected in our financial statements. We refer you to "Quantitative and Qualitative Disclosure about Market Risks."

We could be harmed if the capital markets do not recover or continue to materially decline, or if interest rates substantially rise.

If the capital markets do not recover or continue to materially decline, our earnings would decrease as a result of pension expenses that we would incur. In addition, we might not be able to finance our operations on terms we consider acceptable and our net cash flows could decrease due to higher interest rates.

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.

“Bopd” Barrels of oil produced per day.

“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.

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“Dekatherm” A thermal unit of energy equal to 1,000,000 British thermal units (Btu’s), that is, the equivalent of 1,000 cubic feet of gas having a heated content of 1,000 Btu’s per cubic foot.

“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 and non-cash ceiling test write-downs of oil and gas properties. We refer you to “Business—Other Items—Reconciliation of Non-GAAP Measures” in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA with our operating income as derived 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.

“Finding and development costs” Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized pursuant to generally accepted accounting principles, including any capitalized general and administrative expenses.

“Farm-in or farm-out” An agreement under which the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in” while the interest transferred by the assignor is a “farm-out.”

“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.”

“LIBOR” Represents the London Inter-Bank Overnight Rate of interest.

“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.

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“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.

“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.

“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.

“Proved undeveloped reserves” Reserves that are expected to be recovered from new wells on developed acreage where the subject reserves cannot be recovered without drilling additional wells.

“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.”

“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 re-drilling the same well-bore to reach a new reservoir after production from the original reservoir has been abandoned.

“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.

“Step-out well” A well drilled adjacent to a proven well but located in an unproven area; a well located a “step out” from proven territory in an effort to determine the boundaries of a producing formation.

“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 a gas or oil reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission.

“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 2. PROPERTIES

For additional information about our natural gas and oil operations, we refer you to Notes 5 and 6 to the financial statements. For information concerning capital expenditures, we refer you to “Management’s Discussion and Analysis of

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Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Expenditures”. We also refer you to “Selected Financial Data” for information concerning natural gas and oil produced.

The following table provides information concerning miles of pipe of our gas distribution systems. For a further description of Arkansas Western’s properties, we refer you to “Business—Natural Gas Distribution.”

	Total
Gathering	389
Transmission	986
Distribution	3,823
	5,198

The following information is provided to supplement that presented in Item 8. 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, 2002:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Arkoma	156,955	99,341	228,113	163,771
East Texas	9,711	5,529	12,216	10,588
Permian Basin	46,283	22,391	73,390	17,034
Gulf Coast	124,465	57,962	74,963	24,808
	337,414	185,223	388,682	216,201

Producing wells as of December 31, 2002:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Arkoma	813	410.9	—	—	813	410.9
East Texas	49	46.1	—	—	49	46.1
Permian Basin	124	20.5	262	122.6	386	143.1
Gulf Coast	52	23.7	27	10.2	79	33.9
	1,038	501.2	289	132.8	1,327	634.0

Wells drilled during the year:

Year	Exploratory					
	Productive Wells		Dry Holes		Total	
	Gross	Net	Gross	Net	Gross	Net
2002	9.0	4.2	6.0	2.7	15.0	6.9
2001	13.0	6.5	8.0	3.8	21.0	10.3
2000	13.0	4.0	12.0	4.8	25.0	8.8

Year	Development					
	Productive Wells		Dry Holes		Total	
	Gross	Net	Gross	Net	Gross	Net
2002	36.0	27.5	10.0	5.1	46.0	32.6
2001	67.0	29.5	11.0	2.9	78.0	32.4
2000	65.0	21.9	14.0	6.3	79.0	28.2

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Wells in progress as of December31, 2002:

	Gross	Net
Exploratory	1.0	0.3
Development	3.0	2.8
Total	4.0	3.1

During 2002, we were required to file Form23, "Annual Survey of Domestic Natural Gas and Oil Reserves," with the Department of Energy. The basis for reporting reserves on Form23 is not comparable to the reserve data included in Note 6 to the financial statements in Item8 to this Report. The primary differences are that Form23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties where we are the operator.

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 those 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. We accrue 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 our operations or on our financial position.

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

No matters were submitted during the fourth quarter of the fiscal year ended December31, 2002, to a vote of security holders, through the solicitation of proxies or otherwise.

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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	58	6
Greg D. Kerley	Executive Vice President and Chief Financial Officer	47	13
Richard F. Lane	Executive Vice President, Southwestern Energy Production Company and SEECO, Inc.	45	4
Mark K. Boling	Executive Vice President, General Counsel and Secretary	45	1
Charles V. Stevens	Senior Vice President, Arkansas Western Gas Company	53	14

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 his present position 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. Stevens has served us in his present position since December 1997. Previously, he served as Vice President of Arkansas Western Gas Company from 1988 to 1997.

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 AND RELATED SHAREHOLDER MATTERS

Our common stock is traded on the New York Stock Exchange under the symbol "SWN." At December 31, 2002, we had 2,079 shareholders of record. The following prices represent the range of high and low intra-day market prices of our common stock on the New York Stock Exchange for the periods indicated.

Quarter Ended	Range of Market Prices			
	2002		2001	
March 31	\$ 12.80	\$ 9.60	\$ 11.20	\$ 8.76
June 30	15.25	12.40	16.35	8.77
September 30	15.22	9.51	13.50	10.45
December 31	12.44	10.27	13.05	9.50

We have indefinitely suspended payment of quarterly dividends on its common stock. Additionally, at the present time, the payment of dividends is prohibited by our current revolving credit facility.

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the six-year period ended December 31, 2002. This information and the notes thereto is 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.”

	2002	2001	2000	1999	1998	1997
	(in thousands except share, per share, shareholder data and percentages)					
Financial Review						
Operating revenues						
Exploration and production	\$ 122,207	\$ 153,937	\$ 110,920	\$ 75,039	\$ 86,232	\$ 100,129
Gas distribution	115,850	147,282	151,234	132,420	134,711	154,155
Gas marketing and other	131,514	190,773	208,196	137,942	97,795	83,511
Intersegment revenues	(108,069)	(147,065)	(106,467)	(65,005)	(52,433)	(61,606)
	261,502	344,927	363,883	280,396	266,305	276,189
Operating costs and expenses						
Gas purchases – utility	48,388	68,161	58,669	45,370	39,863	46,806
Gas purchases – marketing	37,927	68,010	133,221	92,851	73,235	63,054
Operating and general	64,600	64,108	59,790	57,957	61,915	59,167
Unusual items	—	—	111,288	—	—	—
Depreciation, depletion and amortization	53,992	52,899	45,869	41,603	46,917	48,208
Write-down of natural gas and oil properties	—	—	—	—	66,383	—
Taxes, other than income taxes	10,090	9,080	8,515	6,557	6,943	7,018
	214,997	262,258	417,352	244,338	295,256	224,253
Operating income (loss)	46,505	82,669	(53,469)	36,058	(28,951)	51,936
Interest expense, net	(21,466)	(23,699)	(24,689)	(17,351)	(17,186)	(16,414)
Other income (expense)	(566)	(799)	1,997	(2,331)	(3,956)	(5,017)
Minority interest in partnership	(1,454)	(930)	—	—	—	—
Income (loss) before income taxes	23,019	57,241	(76,161)	16,376	(50,093)	30,505
Income taxes	—	—	—	537	(6,029)	(732)
Current						
Deferred	8,708	21,917	(29,474)	5,912	(13,467)	12,522
	8,708	21,917	(29,474)	6,449	(19,496)	11,790
Net income (loss)	\$ 14,311	\$ 35,324	\$ (46,687)	\$ 9,927	\$ (30,597)	\$ 18,715
Cash flow from operations, before working capital changes	\$ 79,775	\$ 112,697	\$ (28,917) (1)	\$ 60,818	\$ 73,673	\$ 85,031
Cash flow from operations, net of working capital changes	\$ 77,574	\$ 144,583	\$ (53,203) (1)	\$ 58,131	\$ 93,708	\$ 79,483
Return on equity	8.1%	19.3%	n/a	5.2%	n/a	8.5%
Common Stock Statistics						
Earnings (loss) per share:						
Basic	\$.57	\$ 1.40	\$ (1.86)	\$.40	\$ (1.23)	\$.76
Diluted	\$.55	\$ 1.38	\$ (1.86)	\$.40	\$ (1.23)	\$.76
Cash dividends declared and paid per share	\$ —	\$ —	\$.12	\$.24	\$.24	\$.24

Diluted book value per share	\$	6.81	\$	7.15	\$	5.64	\$	7.63	\$	7.47	\$	8.94
Market price at year-end	\$	11.45	\$	10.40	\$	10.38	\$	6.56	\$	7.50	\$	12.88
Number of shareholders of record at year-end		2,079		2,124		2,192		2,268		2,333		2,379
Average diluted shares outstanding		26,052,238		25,601,110		25,043,586		24,947,021		24,882,170		24,777,906

- (1) Cash flow from operations before working capital changes for 2000 would have been \$82.4million excluding the effects of unusual and extraordinary items. Cash flow from operations, net of working capital changes, for 2000 would have been \$58.1million excluding the effects of unusual and extraordinary items.

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	2002	2001	2000	1999	1998	1997
Capitalization (in thousands)						
Total debt, including current portion	\$ 342,400	\$ 350,000	\$ 396,000	\$ 302,200	\$ 283,436	\$ 299,543
Common shareholders' equity (1)	177,488	183,086	141,291	190,356	185,856	221,565
Total capitalization	\$ 519,888	\$ 533,086	\$ 537,291	\$ 492,556	\$ 469,292	\$ 521,108
Total assets	\$ 740,162	\$ 743,123	\$ 705,378	\$ 671,446	\$ 647,620	\$ 710,866
Capitalization ratios:						
Debt	65.9%	65.7%	73.7%	61.4%	60.3%	57.2%
Equity	34.1%	34.3%	26.3%	38.6%	39.7%	42.8%
Capital Expenditures (in millions)						
Exploration and production	\$ 85.2	\$ 99.0	\$ 69.2	\$ 59.0	\$ 52.4	\$ 73.5
Gas distribution	6.1	5.3	6.0	7.1	10.1	12.6
Other	.8	1.8	.5	.9	1.9	2.7
	\$ 92.1	\$ 106.1	\$ 75.7	\$ 67.0	\$ 64.4	\$ 88.8
Exploration and Production						
Natural gas:						
Production, Bcf	36.0	35.5	31.6	29.4	32.7	33.4
Average price per Mcf	\$ 3.00	\$ 3.85	\$ 2.88	\$ 2.21	\$ 2.34	\$ 2.57
Oil:						
Production, MBbls	682	719	676	578	703	749
Average price per barrel	\$ 21.02	\$ 23.55	\$ 22.99	\$ 17.11	\$ 13.60	\$ 19.02
Total gas and oil production, Bcfe	40.1	39.8	35.7	32.9	36.9	37.9
Lease operating expenses per Mcfe	\$.45	\$.45	\$.40	\$.35	\$.34	\$.36
Taxes other than income taxes per Mcfe	\$.19	\$.17	\$.16	\$.09	\$.09	\$.09
Proved reserves at year-end:						
Natural gas, Bcf	374.6	355.8	331.8	307.5	303.7	291.4
Oil, MBbls	6,784	7,704	8,130	7,859	6,850	7,852
Total reserves, Bcfe	415.3	402.0	380.6	354.7	344.8	338.5
Gas Distribution (2)						
Sales and transportation volumes, Bcf:						
Residential	9.0	8.4	10.9	10.8	11.1	12.6
Commercial	6.2	6.1	7.6	7.6	7.6	8.4
Industrial	1.5	2.5	3.5	3.5	4.2	6.6
End-use transportation	8.4	7.0	8.3	9.6	8.8	6.6
Off-system transportation	25.1	24.0	30.3	31.5	31.7	34.2
	2.2	3.1	3.1	4.8	1.1	2.8
	27.3	27.1	33.4	36.3	32.8	37.0
Customers at year-end:						
Residential	122,906	119,856	119,024	158,606	156,384	154,864
Commercial	16,448	16,177	16,282	21,929	22,229	21,431
Industrial	189	209	228	290	303	311
	139,543	136,242	135,534	180,825	178,916	176,606
Degree days	3,950	3,654	3,994	3,179	3,472	4,131
Percent of normal	98%	91%	100%	79%	87%	103%

- (1) Shareholders' equity includes an accumulated comprehensive loss of \$17.4million in 2002 (\$14.0million related to our cash flow hedges and \$3.4million related to our pension plan) and accumulated comprehensive income of \$5.8million in 2001 related to our cash flow hedges.
- (2) Gas distribution statistics include the operations of the Missouri properties through the sale date of May31, 2000.

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

This Form10-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 "Risk Factors" and elsewhere in this annual report. You should read the following discussion with the "Selected Financial Data" and our financial statements and related notes included elsewhere in this Form10-K.

OVERVIEW

We operate in three segments: Exploration and Production, Natural Gas Distribution and Marketing, Transportation and Other. Our financial results depend on a number of factors, in particular natural gas and oil prices, the seasonality of our customers' need for natural gas and our ability to market natural gas and oil on economically attractive terms to our customers. There has been significant price volatility in the natural gas and crude oil market in recent years. The volatility was attributable to a variety of factors impacting supply and demand, including weather conditions, political events and economic events we cannot control or predict.

Our net income decreased from \$35.3million in 2001, or \$1.38 per share on a fully diluted basis, to \$14.3million, or \$0.55 per share in 2002. This decrease in net income was primarily a result of the negative impact of lower realized natural gas and oil prices on the operating income of our EP segment. A decrease in the operating income for our gas distribution segment also negatively impacted our net income in 2002. In 2000, we reported a net loss of \$46.7million, which included one-time charges for a \$109.3million judgment we paid in connection with the Hales lawsuit and \$2.0million related to other litigation, a loss on the early retirement of debt, and a \$3.2million gain from the sale of our Missouri utility properties. Exclusive of these one-time charges and the gain on sale, net income for 2000 would have been \$20.5 million, or \$0.82 per share.

Revenues were \$261.5million in 2002, a decrease of 24% from \$344.9 million in 2001, primarily reflecting lower realized natural gas and oil prices. Revenues in 2001 decreased 5% to \$344.9million from \$363.9million in 2000, reflecting lower volumes sold to unaffiliated parties by the marketing segment. This decline in volumes reflects our increased focus on marketing our own production and limiting the marketing of third-party volumes in an effort to reduce our credit risk.

RESULTS OF OPERATIONS**Exploration and Production**

	Year ended December 31,		
	2002	2001	2000
Revenues (in thousands)	\$ 122,207	\$ 153,937	\$ 110,920
Operating income (loss) (in thousands)	36,048	69,340	(70,584) (1)
Gas production (Bcf)	36.0	35.5	31.6
Oil production (MBbls)	682	719	676
Total production (Bcfe)	40.1	39.8	35.7
Average gas price per Mcf	\$ 3.00	\$ 3.85	\$ 2.88
Average oil price per Bbl	21.02	23.55	22.99
Average unit costs per Mcfe			
Lease operating expenses	\$ 0.45	\$ 0.45	\$ 0.40
Taxes other than income taxes	0.19	0.17	0.16
General administrative expenses	0.32	0.34	0.32
Full cost pool amortization	1.16	1.14	1.06

- (1) Includes a charge of \$109.3million paid by us in connection with the Hales judgment and a charge of \$2.0 million related to other litigation. Excluding these unusual items, operating income for the EP segment would have been \$40.7million for 2000.

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Revenues, Operating Income and Production

Revenues. Our exploration and production revenues decreased 21% in 2002 to \$122.2million compared to \$153.9million in 2001. The decrease was primarily due to lower prices received for natural gas. Revenues increased 39% in 2001 to \$153.9million from \$110.9million in 2000. The increase was primarily due to increased natural gas and oil production and higher natural gas and oil prices.

Operating Income. Operating income from our exploration and production segment was \$36.0million in 2002 compared to \$69.3million in 2001, and \$40.7 million in 2000, excluding the impact of the Hales judgment and other unusual items charged that year. The decrease in 2002 was primarily due to the decrease in revenues caused by the lower realized natural gas and oil prices. The increase in 2001 was due to an 11% increase in natural gas and oil production and higher prices realized, partially offset by increased operating costs and expenditures.

Production. Gas and oil production totaled 40.1 Bcfe in 2002, 39.8 Bcfe in 2001 and 35.7 Bcfe in 2000. Overall production in 2002 was up slightly over 2001 as increased production from our Overton Field properties in East Texas and from our Gulf Coast properties more than offset production declines in our Arkoma Basin and Permian Basin properties, and the sale of our non-strategic Mid-Continent properties in the fourth quarter of 2002. The increase in 2001 production volumes resulted from successful exploration and development of our South Louisiana properties, the development of our Overton Field and increased production in the Arkoma Basin.

Gas sales to unaffiliated purchasers were 30.6 Bcf in 2002, up from 30.4 Bcf in 2001 and 23.8 Bcf in 2000. 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 Arkansas Western were 5.4 Bcf in 2002, 5.1 Bcf in 2001 and 7.8 Bcf in 2000. The increase in 2002 intersegment sales resulted from increased deliveries to Arkansas Western under our baseload contracts. The decrease in sales in 2001 was caused by Arkansas Western's reduced supply requirements due to warmer weather and the sale of the utility's Missouri gas distribution properties in May 2000. Weather in 2002, as measured in degree days, was 2% warmer than normal and 8% colder than the prior year. Weather in 2001 was 9% warmer than both normal and the prior year and was normal in 2000. Our gas production provided approximately 37% of the utility's requirements in 2002, 33% in 2001 and 42% in 2000.

Future sales to Arkansas Western's gas distribution systems will be dependent upon our success in obtaining gas supply contracts with the utility systems. In the future, we will continue to bid to obtain these gas supply contracts, although there is no assurance that we will be successful. If successful, we cannot predict the amount of fixed demand charges, if any, that would be associated with the new contracts. We expect future increases in our gas production to come primarily from sales to unaffiliated purchasers. 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. Additionally, we hold a large amount of undeveloped leasehold acreage and producing acreage, and have an inventory of drilling leads, prospects and seismic data that will continue to be evaluated and developed in the future. Our exploration programs have been directed primarily toward natural gas in recent years.

Commodity Prices

The average price realized for our gas production was \$3.00 per Mcf in 2002, \$3.85 per Mcf in 2001, and \$2.88 per Mcf in 2000. 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 lowered the average gas price \$0.11 per Mcf in 2002, \$0.31 per Mcf in 2001, and \$1.04 per Mcf in 2000. In 2002, the price was reduced \$0.03 per Mcf due to \$1.1 million of basis differential ineffectiveness associated with our cash flow hedges. There was no significant ineffectiveness recorded in 2001. Additionally, we have historically received monthly demand charges related to sales made to our utility segment, which has increased the average gas price realized.

We periodically enter into hedging activities with respect to a portion of our projected natural gas and crude oil production through a variety of financial arrangements intended to support natural gas and oil prices at targeted levels and to minimize the impact of price fluctuations (we refer you to Item 7A of this Form 10-K and Note 8 to the financial statements for additional discussion). Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2002, we had hedges in place on 42.6 Bcf of gas production. Subsequent to December 31, 2002 and prior to February 14, 2003, we hedged an additional 3.0 Bcf of future gas production. At December 31, 2002 we had hedges in place on 240,000 barrels of future oil production. Subsequent to

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December 31, 2002 and prior to February 14, 2003, we hedged an additional 100,000 barrels of future oil production. As of February 14, 2003, we have hedged approximately 75% of our 2003 anticipated gas production level and 65% of our anticipated oil production level.

Disregarding the impact of hedges, we would normally expect the average price received for our gas production to be approximately \$0.10 to \$0.20 per Mcf lower than average spot market prices, as market differentials that reduce the average prices received are partially offset by demand charges received under the contracts covering our intersegment sales to our utility systems. Future changes in revenues from sales of our gas production will be dependent upon changes in the market price for gas, access to new markets, maintenance of existing markets, and additions of new gas reserves.

We realized an average price of \$21.02 per barrel for our oil production for the year ended December 31, 2002, down from \$23.55 per barrel for 2001 and \$22.99 per barrel for 2000. Our hedging activities lowered the average oil price \$2.92 per barrel in 2002, \$0.03 per barrel in 2001 and \$6.39 per barrel in 2000. Disregarding the impact of hedges, we expect the average price received for our oil production to be approximately \$1.25 lower than posted spot market prices.

Operating Costs and Expenses

Lease operating expenses per Mcfe for this business segment were \$0.45 in 2002 and 2001, compared to \$0.40 in 2000. Taxes other than income taxes per Mcfe were \$0.19 in 2002, compared to \$0.17 in 2001 and \$0.16 in 2000. The increases in per unit lease operating expenses in 2002 and 2001 were due to increased workover expenses and changes in the geographic mix of production. Lease operating expense per unit should decrease in the future as a result of increased production from our Overton Field (lower average cost as compared to other areas), decreased production in Permian Basin properties (higher average cost as compared to other areas) and the sale of our Mid-Continent properties that had the highest average cost per unit of all operating areas. The increases in 2002 and 2001 taxes other than income taxes per Mcfe were due to increased severance and ad valorem taxes that resulted from generally higher commodity prices and from the changing mix of production among taxing jurisdictions. General and administrative expenses per Mcfe were \$0.32 in 2002, compared to \$0.34 in 2001 and \$0.32 in 2000. The increase in general and administrative costs per Mcfe in 2001 was due primarily to increased legal costs related to the resolution of litigation (approximately \$0.07 per Mcfe). Excluding the impact of these litigation costs in 2001, general and administrative costs in 2002 were higher per unit due to increased pension, insurance and salary costs.

Our full cost pool amortization rate averaged \$1.16 per Mcfe for 2002, compared to \$1.14 in 2001 and \$1.06 in 2000. The rate increased in 2002 and 2001, due primarily to negative revisions of proved reserves that resulted from a decline in average gas prices and to a \$6.6million decline in 2001 in the balance of unevaluated costs excluded from amortization in the full cost pool. Unevaluated costs excluded from amortization have declined from \$37.6million at the beginning of 2000 to \$25.5million at the end of 2002.

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under this method, all such costs (productive and nonproductive) 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, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved 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 this 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 to calculate the ceiling value of their reserves. At December 31, 2002, 2001 and 2000, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2002, our standardized measure was calculated based upon quoted market prices of \$4.74 per Mcf for gas and \$31.20 per barrel for oil, adjusted for market differentials. A decline in natural gas and oil prices from year-end 2002 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

In November 2002, we sold our remaining non-strategic Mid-Continent properties, including our properties in the Sho-Vel-Tum area in southern Oklahoma, the Anadarko Basin in western Oklahoma and the Sooner Trend in northwestern Oklahoma, for a total of \$26.4million. These properties represented approximately 32.9 Bcfe of reserves and produced approximately 2.5 Bcfe annually. We expect this divestiture to result in a decrease in our future average production costs per unit of production.

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In 2001, our subsidiary, SEPCO, formed a limited partnership with an investor to drill and complete 14 development wells in SEPCO's Overton Field located in Smith County, Texas. The Overton properties were acquired by SEPCO in April 2000 and have multiple development locations through the downspacing of the existing producing units. Because SEPCO is the sole general partner and owns a majority interest in the partnership, operating and financial results for the partnership are consolidated with our other operations and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. During 2002 and 2001, the minority interest owner in the partnership contributed \$0.5million and \$13.5million, respectively, in capital to the limited partnership. The investor's share of 2002 and 2001 revenues, less operating costs and expenses, was \$1.5million and \$0.9million, respectively.

Inflation impacts us by generally increasing our operating costs and the costs of our capital additions. The effects of inflation on our operations prior to 2000 have been minimal due to low inflation rates. However, during both 2001 and 2000, the impact of inflation intensified in certain areas of our exploration and production segment as shortages in drilling rigs, third-party services and qualified labor developed due to an overall increase in the activity level of the domestic natural gas and oil industry. We feel this impact has been decreasing in 2002 with the relative stabilization of commodity prices. Additionally, Southwestern has mitigated rising costs in certain situations by obtaining vendor commitments to multiple projects and by offering incentives to vendors for cost reduction efforts that directly impact the amount we pay for their services.

Natural Gas Distribution

The operating results of our gas distribution segment are highly seasonal and the extent and duration of heating weather significantly impacts the profitability of this segment, although we have a weather normalization clause that lessens the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The gas distribution segment's profitability is also dependent upon the timing and amount of regulatory rate increases that are filed with and approved by the APSC. For periods subsequent to allowed rate increases, our profitability is impacted by our ability to manage and control this segment's operating costs and expenses.

	Year Ended December 31,		
	2002	2001	2000(1)
	(\$ in thousands except for per Mcf amounts)		
Revenues	\$ 115,850	\$ 147,282	\$ 151,234
Gas purchases	\$ 66,486	\$ 96,058	\$ 93,992
Operating costs and expenses	\$ 41,801	\$ 40,878	\$ 42,587
Operating income	\$ 7,563	\$ 10,346	\$ 14,655
Deliveries (Bcf)			
Sales and end-use transportation	25.1	24.0	30.4
Off-system transportation	2.2	3.1	3.1
Average number of customers	136,747	134,041	152,773
Average sales rate per Mcf	\$ 6.49	\$ 8.26	\$ 6.55
Heating weather — degree days	3,950	3,654	3,994
Percent of normal	98%	91%	100%

(1) Data for 2000 includes the operations of the Missouri properties through the sale date of May 31, 2000. Excluding the Missouri operations, operating income would have been \$12.6million in 2000.

Revenues and Operating Income

Gas distribution revenues fluctuate due to the effects of warm 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 net income.

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Gas distribution revenues decreased 21% in 2002 and decreased 3% in 2001. The decrease in 2002 was primarily due to a lower average sales rate caused by lower gas prices. The decrease in 2001 was due to the loss of revenues resulting from the sale of the utility's Missouri assets in May 2000 and the effects of warmer weather, partially offset by a higher average sales rate caused by higher gas prices. Weather during 2002 in the utility's service territory was 2% warmer than normal and 8% colder than the prior year, and was 9% warmer than both normal and the prior year in 2001. Weather was normal in 2000.

Operating income for our utility systems decreased 27% in 2002 and 29% in 2001. The decrease in 2002 resulted from increased operating costs and expenses and reduced usage per customer due to customer conservation brought about by high gas prices in 2001. The decrease in 2001 operating income for this segment resulted from the full-year impact of the sale of the utility's Missouri assets, the effects of warmer weather that were not fully offset by the weather normalization clause in its tariffs and increased bad debt expense caused by record high natural gas prices experienced in the first part of 2001.

Deliveries and Rates

In 2002, Arkansas Western sold 16.7 Bcf to its customers at an average rate of \$6.49 per Mcf, compared to 17.0 Bcf at \$8.26 per Mcf in 2001 and 22.1 Bcf at \$6.55 per Mcf in 2000. Additionally, Arkansas Western transported 8.4 Bcf in 2002, 7.0 Bcf in 2001 and 8.3 Bcf in 2000 for its end-use customers. The decrease in volumes sold in 2002 resulted from customer conservation brought about by high gas prices in 2001 and from several industrial customers moving from system supply to transportation, partially offset by customer growth. The decrease in volumes sold and transported in 2001 resulted from the sale of the utility's Missouri properties in 2000 and warmer weather. Arkansas Western's tariffs contain 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 fluctuations in the average sales rates reflect changes in the average cost of gas purchased for delivery to our customers, which are passed through to customers under automatic adjustment clauses.

Total deliveries to industrial customers of the utility segment, including transportation volumes, were 9.9 Bcf in 2002, 9.5 Bcf in 2001 and 11.8 Bcf in 2000. The increase in deliveries in 2002 resulted from industrial growth in the region. The decline in deliveries in 2001 resulted from warmer heating weather and the sale of the utility's Missouri assets. Arkansas Western also transported 2.2 Bcf of gas through its gathering system in 2002 compared to 3.1 Bcf in both 2001 and 2000 for off-system deliveries, all to the Ozark Gas Transmission System. The level of off-system deliveries each year generally reflects the changes of on-system demands of our gas distribution systems for our gas production. The average off-system transportation rate was approximately \$0.13 per Mcf, exclusive of fuel, in 2002 and 2001, and \$0.10 per Mcf in 2000.

Gas distribution revenues in future years will be impacted by the utility's gas purchase costs, customer growth and rate increases allowed by the APSC. In recent years, Arkansas Western has experienced customer growth of approximately 2% to 3% annually in its Northwest Arkansas service territory, while it has experienced little or no customer growth in its service territory in Northeast Arkansas. Based on current economic conditions in our service territories, we expect this trend in customer growth to continue.

Operating Costs and Expenses

The changes in purchased gas costs for the gas distribution segment reflect volumes purchased, prices paid for supplies, the mix of purchases from various gas supply contracts (base load, swing and no-notice) and the sale of Missouri assets as discussed above. Operating costs and expenses increased in 2002 as compared to 2001 due to general inflationary effects and increased pension and insurance expenses. Other operating costs and expenses of the gas distribution segment decreased in 2001 as compared to 2000 due to the sale of the utility's Missouri assets. Operating costs in 2001 also included increased bad debt expense caused by high natural gas prices in the 2000-2001 winter heating season.

In October 1998, Arkansas Western instituted a competitive bidding process for its gas supply. Additionally, Arkansas Western annually submits its gas supply plan to the general staff of the APSC. As a result of the bidding process under the plan filed for the 2002-2003 gas purchase year, SEECO successfully bid on gas supply packages representing approximately two-thirds of the requirements for Arkansas Western for 2003. The contracts awarded to SEECO expire through 2005. Arkansas Western enters into hedging activities from time to time with respect to its gas purchases to

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protect against the inherent price risks of adverse price fluctuations. We refer you to “Quantitative and Qualitative Disclosure About Market Risks” and Note 8 to the financial statements for additional information.

Inflation impacts our gas distribution segment by generally increasing our operating costs and the costs of our capital additions. The effects of inflation on the utility’s operations in recent years have been minimal due to low inflation rates. Additionally, delays inherent in the rate-making process prevent us from obtaining immediate recovery of increased operating costs of our gas distribution segment.

Regulatory Matters

Arkansas Western’s rates and operations are regulated by the APSC. Arkansas Western operates through municipal franchises that are perpetual by virtue of state law, but are not 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. 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 unbundled residential sales services from transportation services in an effort to promote greater competition. No such legislation or regulatory directives related to natural gas are presently pending in Arkansas.

In Arkansas, the state legislature enacted Act 1556 for the deregulation of the retail sale of electricity by 2002. Act 1556 was modified by Act 324 of 2001 delaying the implementation of electric deregulation to not earlier than October 2003 and no later than October 2005. In December 2001, the APSC submitted its annual report to the Arkansas legislature on the development of electric deregulation and recommended that the legislature consider suspending deregulation to the year 2010 or 2012, or repeal Act 1556 (as modified by Act 324). Furthermore, legislation has been recently introduced seeking to repeal the deregulation of the retail sale of electricity. It is unknown what final legislation will be adopted or, if it is adopted, what its final form will be. If electric deregulation occurs in Arkansas, legislative or regulatory precedents may be set that would also affect natural gas utilities in the future. These issues may include further unbundling of services and the regulatory treatment of stranded costs.

Arkansas Western has historically maintained a substantial price advantage over electricity for most applications. This has enabled the utility to achieve excellent market penetration levels. However, during 2001 the high gas prices experienced in the 2000-2001 heating season temporarily eroded the price advantage. Arkansas Western has made progress in regaining price advantage in its markets as gas prices have declined from the levels experienced in the winter of 2000-2001.

Arkansas Western filed an application with the APSC on November 8, 2002, for a rate increase of \$11.0 million annually. The APSC has ten months to reach a decision on the amount of an allowed rate increase. As a result, any increase granted will become effective no later than September 2003. Arkansas Western’s last rate increase was approved in December 1996 for the utility’s Northwest region and in December 1997 for the Northeast region. The APSC approved increases of \$5.1 million and \$1.2 million, respectively. During 1999, the APSC initiated a proceeding in which it sought a \$2.3 million reduction in the rates for the Northwest region. In late 1999, the APSC and Arkansas Western reached a settlement in which the Northwest region’s rates were reduced by \$1.4 million. The reduction was primarily due to a downward adjustment to the return on equity that the APSC had established in the 1996 rate case. Rate increase requests, which may be filed in the future, will depend on customer growth, increases in operating expenses, and additional investment in property, plant and equipment. While Arkansas Western continues to experience customer growth and has controlled its costs, its return on investment has declined in recent years.

In February 2001, the APSC approved a 90-day temporary tariff to collect additional gas costs not yet billed to customers through the utility’s normal purchased gas adjustment clause in its approved tariffs. We had significant under-recovered purchased gas costs as a result of the high prices paid for gas supply in the 2000-2001 heating season. The temporary tariff allowed the utility accelerated recovery of these gas costs. In April 2002, Arkansas Western filed a revised purchased gas adjustment clause that provides better matching between the time the gas costs are incurred and the time the costs are recovered. The APSC approved the new clause in May 2002.

In April 2002, the APSC adopted Natural Gas Procurement Plan Rules for utilities. These rules require utilities to take all reasonable and prudent steps necessary to develop a diversified gas supply portfolio. The portfolio should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments that are designed to yield an optimum balance of reliability, reduced volatility and reasonable price. Utilities will be required to submit on an annual basis their gas supply plan, along with their contracting and/or hedging objectives, to the staff of the

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APSC for review and determination as to whether it is consistent with these policy principles. If the plan includes a hedging strategy and it is determined to be consistent with the objectives of the policy principles, utilities will be allowed to flow any hedging gain or loss to customers through the purchased gas adjustment clause. During 2001, Arkansas Western submitted its annual gas supply plan for the 2001-2002 heating season and a revision to its purchased gas adjustment clause for the recovery of hedging gains and losses to the staff of the APSC. In May 2002, Arkansas Western submitted its annual gas supply plan for the 2002-2003 heating season.

Arkansas Western also purchases gas from unaffiliated producers under take-or-pay contracts. We believe that we do not have a significant exposure to liabilities resulting from these contracts and expect to be able to continue to satisfactorily manage our exposure to take-or-pay liabilities.

Marketing, Transportation and Other

Operating income from the marketing, transportation and other segment, which includes income from real property held by our subsidiary, A.W. Realty Company, was \$2.9million in 2002, compared to \$3.0million in 2001 and \$2.5 million in 2000. EBITDA for these segments was \$2.8million in 2002, compared with \$2.4million in 2001 and \$3.0million in 2000. For a further discussion of our EBITDA reconciliation, we refer you to “Business—Other Items—Reconciliation of Non-GAAP Measures.”

Marketing

	Year Ended December 31,		
	2002	2001	2000
Revenues (in millions)	\$ 131.1	\$ 190.3	\$ 207.7
Operating income (in millions)	\$ 2.7	\$ 2.7	\$ 2.5
Gas volumes marketed (Bcf)	45.5	49.6	59.6

Our operating income from marketing was \$2.7million on revenues of \$131.1 million in 2002, compared to \$2.7million on revenues of \$190.3million in 2001, and \$2.5million on revenues of \$207.7million in 2000. We marketed 45.5 Bcf in 2002, compared to 49.6 Bcf in 2001 and 59.6 Bcf in 2000. The decline in total volumes marketed in 2002 and 2001 resulted primarily from the decline in volumes marketed to third parties. This reduction reflects our increased focus on marketing our own production and limiting the marketing of third-party volumes in an effort to reduce our credit risk. Of the total volumes marketed, purchases from our exploration and production subsidiaries accounted for 67% in 2002, 66% in 2001 and 33% in 2000. 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 Disclosure About Market Risks” and Note 8 to the financial statements for additional discussion.

Transportation

The marketing, transportation and other segment also manages our 25% interest in NOARK. At December 31, 2002, Arkansas Western had transportation contracts with Ozark Pipeline for 66.9 MMcf per day of firm capacity. These contracts expire in 2003 and are renewable annually thereafter until terminated with 180days’ notice. NOARK and Arkansas Western are currently renegotiating these contracts. Our recorded pre-tax loss from operations included in other income related to our NOARK investment was \$0.3million in 2002, \$1.5million in 2001, and \$1.8million in 2000. The improvements in operating results since 2000 result primarily from NOARK’s ability to collect higher transportation rates on interruptible volumes. We believe that we will be able to continue to reduce the losses from NOARK and expect our investment in NOARK to be realized over the life of the system. We refer you to Note 7 to the financial statements for additional discussion.

We have severally guaranteed the debt service on a portion of NOARK’s outstanding debt. NOARK’s outstanding debt was \$71.0million at December 31, 2002, and our share of the guarantee was \$42.6million. This debt financed a portion of the original cost to construct the NOARK Pipeline. We were not required to advance any funds to NOARK in 2002, and advanced \$1.4million in 2001 primarily for debt service. We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Off-Balance Sheet Arrangements” and Note 11 to the financial statements for further discussion of our guarantee of NOARK debt.

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In January 2003, Ozark Pipeline sold a 28 mile portion of its pipeline system located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were \$10.0million. We received \$2.5million of cash proceeds from this sale and will record a gain of approximately \$1.0 million in 2003.

Other Income, Costs and Expenses

Interest costs, net of capitalization, were down 9% in 2002 and down 4% in 2001, both as compared to prior years. Interest costs for 2000 have been restated from prior years' presentations to reflect costs incurred for the early extinguishment of debt. These costs were previously presented as a net-of-tax extraordinary item but have been reclassified for presentation purposes as required by SFAS No.145. Interest costs were down in 2002 due to lower average borrowings and a lower average interest rate. A decrease in interest costs in 2001 that resulted from lower average borrowings, a lower average interest rate and the early extinguishment of debt costs discussed above, was partially offset by a lower level of capitalized interest related to our natural gas and oil properties. Interest capitalized decreased 7% in 2002 and 35% in 2001. The reductions in capitalized interest are primarily due to the level of costs excluded from amortization in our exploration and production segment.

Other income (expense)in 2002 resulted from our share of NOARK's results of operations, as discussed above, and interest costs on customer deposits in the gas distribution segment. Other income (expense)in 2001 resulted from our share of NOARK's results of operations, offset by interest income in the gas distribution segment related to under-recovered gas purchase costs. Other income in 2000 resulted from a \$3.2million gain on the sale of our Missouri gas distribution assets and gains from the sale of other miscellaneous assets, partially offset by our share of NOARK's results of operations.

The Hales judgment was the primary cause for our deferred tax benefit of \$29.5million in 2000. Excluding this impact, the changes in the provision for deferred income taxes recorded each year result primarily from the level of taxable income, the collection of under-recovered purchased gas costs, abandoned property costs, and the deduction of intangible drilling costs in the year incurred for tax purposes, netted against the turnaround of intangible drilling costs deducted for tax purposes in prior years. Intangible drilling costs are capitalized and amortized over future years for financial reporting purposes under the full cost method of accounting.

We recorded pension expense of \$0.9million in 2002 and a credit to expense of \$0.1million in 2001. The amount of pension expense recorded by us is determined by actuarial calculations and is also impacted by the funded status of our plans. At December31, 2002 our pension plans were underfunded and a liability of \$5.6million was recorded on the balance sheet. As a result of the underfunded status and actuarial data to be completed in early 2003, we expect to record pension expense of \$3.0million to \$5.0million in 2003. For further discussion of our pension plans, we refer you to Note 4 to the financial statements.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds and our revolving line of credit (discussed below under "Financing Requirements") as our primary sources of liquidity. We may borrow up to \$125.0million under our revolving credit facility from time to time. As of February14, 2003, we had \$106.1million of indebtedness outstanding under the revolving credit facility. We expect our capital expenditures (discussed below under "Capital Expenditures") for 2003 to exceed the funds generated by our operations and the funds that may be available under our credit facility. In December 2002, we filed a shelf registration statement with the SEC pursuant to which we may from time to time during 2003, subject to market conditions, publicly offer equity, debt or other securities.

Net cash provided by operating activities was \$77.6million in 2002, compared to \$144.6million in 2001. In 2000, net cash used in operating activities was \$53.2million as a result of the Hales judgment and the impact of high year-end gas prices on working capital. 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. Net cash from operating activities provided 84% of our capital requirements for routine capital expenditures in 2002, and over 100% in 2001.

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Our cash flow from operating activities is highly dependent upon 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 “Quantitative and Qualitative Disclosure About Market Risks” and Note 8 to the financial statements. 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 cash flow available. If we are unable to raise funds in the capital markets in early 2003 as planned, we will be required to adjust our planned level of investment in capital projects in the EP segment. This, in turn, could negatively impact growth in production volumes and cash flow from operations, which could ultimately affect our ability to meet the covenants contained in the indentures governing our public debt as well as our revolving credit facility agreement. We do not anticipate being unable to meet our covenants and commitments. See “Financing Requirements” for further discussion of our debt covenants.

Capital Expenditures

Capital expenditures totaled \$92.1million in 2002, \$106.1million in 2001, and \$75.7million in 2000. Our exploration and production segment expenditures included acquisitions of interests in natural gas and oil producing properties totaling \$3.5million in 2002, \$7.3million in 2001 and \$7.4million in 2000. Our reported capital investments in 2002 and 2001 include the gross expenditures in the Overton Field partnership discussed previously. The owner of the minority interest in the Overton partnership funded \$0.5million and \$13.5million of our exploration and development expenditures during 2002 and 2001, respectively.

	2002	2001	2000
	(in thousands)		
Exploration and production	\$ 85,201	\$ 98,964	\$ 69,211
Gas distribution	6,115	5,347	5,994
Other	746	1,749	512
	\$ 92,062	\$ 106,060	\$ 75,717

Capital investments planned for 2003 total approximately \$145.6million, consisting of \$137.1million for exploration and production, \$7.7million for gas distribution system improvements and \$0.8million for general purposes. We expect that this level of capital investments in 2003 will allow us to accelerate the development of our Overton Field properties in East Texas, maintain our present markets, explore and develop other existing gas and oil properties, generate new drilling prospects, and finance improvements necessary due to normal customer growth in our gas distribution segment. As discussed above, our 2003 capital investment program is expected to be funded through cash flow from operations, our revolving credit facility, and, subject to market conditions, one or more possible public offerings of equity, debt or other securities. We may adjust our level of future capital investments dependent upon our ability to consummate such offerings and our level of cash flow generated from operations.

Off-Balance Sheet Arrangements

As discussed above in Results of Operations, we hold a 25% general partnership interest in NOARK and account for our investment under the equity method of accounting. We and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK’s 7.15% Notes due 2018. This debt financed a portion of the original cost to construct the NOARK Pipeline. Our share of the guarantee is 60%. At December 31, 2002 and 2001, the outstanding principal amount of these notes was \$71.0million and \$73.0 million, respectively. Our share of the guarantee was \$42.6million and \$43.8 million, respectively. The notes were issued in June 1998 and require semi-annual principal payments of \$1.0million. Under the several guarantee, we are required to fund our share of NOARK’s debt service which is not funded by operations of the pipeline. We were not required to advance any funds to NOARK in 2002, and advanced \$1.4million in 2001 primarily for debt service.

Our share of the results of operations included in other income related to our NOARK investment were losses of \$0.3million in 2002, \$1.5million in 2001, and \$1.8million in 2000. The improvements in operating results since 2000 result primarily from the ability to collect higher transportation rates on interruptible volumes. We believe that we will be able to continue to reduce the losses we have experienced on the NOARK project and expect our investment in NOARK to be realized over the life of the system (see Note 7 of the financial statements for additional discussion).

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NOARK's assets and liabilities as December 31, 2002 and 2001 are as follows:

	2002	2001
	(in thousands)	
Current assets	\$ 15,730	\$ 8,363
Noncurrent assets	169,970	175,299
	\$ 185,700	\$ 183,662
Current liabilities	\$ 7,631	\$ 7,403
Long-term debt	69,000	71,000
Partners' capital	109,069	105,259
	\$ 185,700	\$ 183,662

NOARK's results of operations for 2002, 2001 and 2000 are summarized below:

	2002	2001	2000
	(in thousands)		
Operating revenues	\$ 75,959	\$ 81,662	\$ 73,633
Pre-tax net income (loss)	\$ 3,011	\$ (1,047)	\$ (1,391)

Contractual Obligations and Contingent Liabilities and Commitments

We have assumed various contractual obligations and contingent commitments in the normal course of our operations and financing activities. Significant contractual obligations at December 31, 2002 are as follows:

Contractual Obligations :

	Total	Payments Due by Period			
		Less than 1 Year	1 to 3 Years (in thousands)	3 to 5 Years	More than 5 Years
Long-term debt	\$ 342,400	\$ —	\$ 242,400	—	\$ 100,000
Operating leases (1)	2,653	729	1,428	496	—
Unconditional purchase obligations (2)	—	—	—	—	—
Demand charges (3)	17,312	7,458	3,642	2,485	3,727
Other long-term obligations (4)	1,860	1,860	—	—	—
	\$ 364,225	\$ 10,047	\$ 247,470	\$ 2,981	\$ 103,727

- (1) We lease office space in Houston, Texas, office space in Tulsa, Oklahoma, and approximately twenty vehicles under operating leases expiring through 2006.
- (2) Our utility segment has volumetric commitments for the purchase of gas under competitive bid packages and wellhead contracts. Volumetric purchase commitments at December 31, 2002 totaled 3.1 Bcf, comprised of 1.3 Bcf in less than one year, 1.0 Bcf in one to three years, .5 Bcf in three to five years and .3 Bcf in more than five years. Our volumetric purchase commitments are priced at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.
- (3) Our utility segment has commitments for demand charges on firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers.
- (4) Our significant other contractual obligations for 2003 include approximately \$0.8 million of land leases, approximately \$0.5 million for drilling rig commitments and approximately \$0.6 million of various information technology support agreements.

We refer you to "Financing Requirements" below for a discussion of the terms of our long-term debt.

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Contingent Liabilities or Commitments.

We have the following commitments and contingencies that could create, increase or accelerate our liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Our return on the assets of these plans in 2002 was negative which, combined with other factors, is expected to result in an increase in pension expense and our required funding of the plans for 2003. At December 31, 2002 we recorded an accrued pension benefit liability of \$5.6 million. As a result of the underfunded status and actuarial data to be completed in early 2003, we expect to record pension expense of \$3.0 million to \$5.0 million in 2003. See Note 4 to the financial statements for additional information.

As discussed above in "Off-Balance Sheet Arrangements," we have guaranteed 60% of the principal and interest payments on NOARK's 7.15% Notes due 2018. At December 31, 2002 the principal outstanding for these notes was \$71.0 million. The notes require semi-annual principal payments of \$1.0 million. See Note 11 to the financial statements for additional information.

Financing Requirements

Our total debt outstanding was \$342.4 million at December 31, 2002 and \$350.0 million at December 31, 2001. In July 2001, we arranged an unsecured revolving credit facility with a group of banks to replace our previous short-term credit facility that was put in place in July 2000. The revolving credit facility has a maximum capacity of \$125.0 million and expires in July 2004. At December 31, 2002, we had \$117.4 million of outstanding debt under our revolving credit facility, with \$7.6 million of borrowing availability. The interest rate on the new facility is calculated based upon our debt rating. We are currently paying 150 basis points over LIBOR. We have also entered into interest rate swaps for calendar year 2003 that allow us to pay a fixed average interest rate of 3.8% (based upon current rates under the revolving credit facility) on \$40.0 million of our outstanding revolving debt.

Our revolving credit facility contains covenants, which impose certain restrictions on us. Under the credit agreement at December 31, 2002, we may not issue total debt in excess of 70% of our total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of EBITDA to interest expense at 3.75 or above. Effective March 31, 2003, the percentage of debt to total capital covenant decreases to 65% and the minimum ratio of EBITDA to interest expense covenant increases to 4.0. These covenants continue to change over the term of the credit facility and generally become more restrictive. We were in compliance with our debt agreements at December 31, 2002. Although we do not anticipate debt covenant violations, our ability to comply with our debt agreements 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.

In 1997, we publicly issued \$60.0 million of 7.625% Medium-Term Notes due 2027 and \$40.0 million of 7.21% Medium-Term Notes due 2017. In 1995, we publicly issued \$125.0 million of 6.7% Notes due in 2005. Our publicly traded notes are rated BBB by Standard and Poor's and Ba2 by Moody's. During 2002, Moody's downgraded our public debt from our previous Baa3 rating. The interest rate under the revolving credit facility increased 12.5 basis points in July 2002 as the result of the downgrade of our public debt by Moody's. Further downgrades of our public debt could increase the costs of funds under our revolving credit facility.

In December 2002, we filed a shelf registration statement with the SEC for the purpose of qualifying the potential sale from time to time of up to an aggregate \$300 million of equity, debt and other securities.

In June 1998, the NOARK partnership issued \$80.0 million of 7.15% Notes due 2018. The notes require semi-annual principal payments of \$1.0 million that began in December 1998. We account for our investment in NOARK under the equity method of accounting and do not consolidate the results of NOARK. We and Enogex, the other general partner of NOARK, have severally guaranteed the principal and interest payments on the NOARK debt. Our share of the several guarantee is 60% and amounted to \$42.6 million at December 31, 2002. We did not advance any funds to NOARK in 2002. In 2001, we advanced \$1.4 million to NOARK to fund its share of debt service payments. If NOARK is unable to generate sufficient cash in the future to service our debt and we are required to contribute cash to fund our share of the debt service guarantee, we could be required to record our share of the NOARK debt commitment under current accounting rules.

At the end of 2002, our capital structure consisted of 65.9% debt (excluding our several guarantee of NOARK's obligations) and 34.1% equity, with a ratio of EBITDA to interest expense of 4.65. EBITDA is a measure required by our debt covenants and is defined

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as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Shareholders' equity in the December 31, 2002 balance sheet includes an accumulated other comprehensive loss of \$14.0 million related to our hedging activities that is required to be recorded under the provisions of SFAS No. 133. This amount is based on current market values of our hedges at December 31, 2002 and does not necessarily reflect the value that we will receive when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our debt covenants as to capitalization percentages exclude the effects of non-cash entries that result from SFAS No. 133 as well as the non-cash impact of any full cost ceiling write downs. Our capital structure, including our several guarantee of NOARK's obligations, would be 66.8% debt and 33.2% equity at December 31, 2002 without consideration of the accumulated other comprehensive loss related to SFAS No. 133. As part of our strategy to insure cash flow to fund our operations and meet the restrictive covenant tests under our debt agreements, we have hedged approximately 75% of our expected 2003 gas production and 65% of our expected 2003 oil production. The amount of long-term debt we incur is dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near current levels throughout 2003 and our capital expenditure plans do not change from current expectations, we do not expect to materially reduce our long-term debt in 2003. If commodity prices significantly decrease, we may incur additional long-term debt to fund our capital expenditure plans or we may modify our capital expenditure plans.

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 operating income as derived from our audited financial information.

Working Capital

We maintain access to funds that may be needed to meet seasonal requirements through our credit facility described above. We had positive working capital of \$1.6 million at the end of 2002 and \$21.7 million at the end of 2001. Current assets decreased by 18% in 2002 and current liabilities increased 4%. The decrease in current assets at December 31, 2002 was due primarily to decreases in amounts recorded in accordance with SFAS No. 133 for derivative activities, and decreases in accounts receivable, inventories and cash. Decreases in accounts payable and over-recovered purchased gas costs in current liabilities were more than offset by increases in amounts recorded as current liabilities for derivative activities. At December 31, 2002, we had over-recovered purchased gas costs of \$5.7 million.

CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis. Under these rules, all such costs (productive and nonproductive) 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, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

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. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on December 31, 2002, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

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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. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the disclosure 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 engage the services of an independent petroleum consulting firm to review reserves as prepared by our reservoir engineers.

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. 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 SFAS No.133 and are recorded at fair value in our financial statements. We utilize market-based quotes from our hedge counterparties to value these open positions. 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 ineffective hedge, derivative not qualifying for accounting treatment as a hedge, or ineffective portion of a hedge is recognized immediately in earnings. Future market price volatility could create significant changes to the hedge positions recorded in our financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" in this Form10-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 regulatory commission 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 regulatory commission has not required any unbundling of services, although large industrials are free to contract for their own gas supply. There are no regulations relating to unbundling of services currently anticipated; 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 may be required.

Pension Accounting

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 4 to the 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 2002, the discount rate assumed is 6.8% and the expected return assumed is 9.0%. This compares to a discount rate of 7.0% and an expected return of 9.0% used in 2001.

Using the assumed rates discussed above, we recorded pension expense of \$0.9million in 2002 and a credit to expense of \$0.1million in 2001. We reflected a pension liability of \$5.6million at December31, 2002 and a prepaid benefit cost of \$4.9million at December31, 2001.

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Assuming a 1% change in the 2002 rates (lower discount rate and lower rate of return), we would have recorded pension expense of \$1.7million in 2002, and recorded an accrued pension liability of \$10.7million at December31, 2002.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the exploration and production segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12months 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 10.4 Bcf at \$3.10 at December31, 2002 and 10.1 Bcf at \$3.05 at December31, 2001.

The gas in inventory for the exploration and production segment is used primarily to supplement production in meeting the segment's contractual commitments including delivery to customers of our gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the gas distribution segment to the exploration and production segment, 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. Declines in the future market price of natural gas could result in us writing down our carrying cost of gas in storage.

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

FORWARD-LOOKING INFORMATION

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section27A of the Securities Act of 1933, as amended, and Section21E 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.

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 prospectus supplement and accompanying prospectus 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 commodity prices for natural gas and oil;
- the timing and extent of our success in discovering, developing, producing, and estimating reserves;
- our future property acquisition or divestiture activities;
- the effects of weather and regulation on our gas distribution segment;
- increased competition;
- the impact of federal, state and local government regulation;

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- the financial impact of accounting regulations;
- changing market conditions and prices (including regional basis differentials);
- the comparative cost of alternative fuels;
- the availability of oil field personnel, services, drilling rigs, and other equipment; and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that these forward-looking statements 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 this Form10-K.

Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of natural gas and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form10-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 DISCLOSURE ABOUT MARKET RISKS

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. The 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 Risks

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 customers and their dispersion across geographic areas. No single customer accounts for greater than 4% of accounts receivable. 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 our debt obligations, principal cash flows and related weighted-average interest rates by expected maturity dates. Variable average interest rates reflect the rates in effect at December 31, 2002 for borrowings under our credit facility. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest

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rate swaps may be used to adjust interest rate exposures when appropriate. We have entered into interest rate swaps for the calendar year 2003 that allow us to pay a fixed average interest rate of 3.8% (based upon current rates under the revolving credit facility) on \$40.0million of our outstanding revolving debt.

	2003	2004	Expected Maturity Date				Total	Fair Value 12/31/02
			2005	2006	2007	Thereafter		
Fixed Rate	—	—	\$ 125.0	—	—	\$ 100.0	\$ 225.0	\$ 222.6
Average Interest Rate	—	—	6.70%	—	—	7.46%	7.04%	
Variable Rate	—	\$117.4	—	—	—	—	\$ 117.4	\$ 117.4
Average Interest Rate	—	3.23%	—	—	—	—	3.23%	

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 marketing segment, and to hedge the purchase of gas in our utility 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 receives from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

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. 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 ensure limited credit risk exposure.

The following table provides information about our financial instruments that are sensitive to changes in commodity prices. The table presents the notional amount in Bcf and MBbls, the weighted average contract prices, and the total dollar contract amount by expected maturity dates. The “Carrying Amount” for the contract amounts is calculated as the contractual payments for the quantity of gas or oil to be exchanged under futures contracts and does not represent amounts recorded in our financial statements. The “Fair Value” represents values for the same contracts using comparable market prices at December 31, 2002. At December 31, 2002, the “Carrying Amount” exceeded the “Fair Value” of these financial instruments by \$20.5million.

	Expected Maturity Date			
	2003		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Production and Marketing				
Natural Gas				
Swaps with a fixed-price receipt				
Contract volume (Bcf)	13.3		7.2	
Weighted average price per Mcf	\$ 3.47		\$ 4.01	
Contract amount (in millions)	\$ 46.2	\$ 31.3	\$ 28.8	\$ 27.0
Price collars				
Contract volume (Bcf)	15.9		8.0	
Weighted average floor price per Mcf	\$ 3.16		\$ 3.50	
Contract amount of floor (in millions)	\$ 50.1	\$ 50.8	\$ 28.0	\$ 30.2
Weighted average ceiling price per Mcf	\$ 4.84		\$ 4.65	
Contract amount of ceiling (in millions)	\$ 76.7	\$ 71.3	\$ 37.2	\$ 33.2
Oil				
Swaps with a fixed-price receipt				
Contract volume (MBbls)	240		—	
Weighted average price per Bbl	\$ 25.40		—	
Contract amount (in millions)	\$ 6.1	\$ 5.7	—	—
Natural Gas Purchases				
Swaps with a fixed-price payment				
Contract volume (Bcf)	2.7		—	
Weighted average price per Mcf	\$ 3.42		—	
Contract amount (in millions)	\$ 9.2	\$ 12.3	—	—

At December 31, 2002, we had financial instruments that are sensitive to changes in interest rates. This \$40.0 million of notional interest rate swaps have an average fixed rate of 2.3%. Their carrying amount of \$1.0 million is calculated as the contractual payments for interest on the notional amount to be exchanged under futures contracts and does not represent amounts recorded in our financial statements. The fair value of \$0.6 million represents the value for the same contracts using comparable market prices at December 31, 2002. At December 31, 2002, the "Carrying Amount" exceeded the "Fair Value" of these interest rate swaps by \$0.4 million.

Subsequent to December 31, 2002 and prior to February 14, 2003, we entered into additional derivative contracts to hedge gas and oil production sales. A price collar hedge on 3.0 Bcf of 2003 gas production sales has a floor of \$4.00 per Mcf and a ceiling of \$5.97 per Mcf. A fixed price swap on oil production of 100 MBbls in 2003 will yield \$29.40 per barrel.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF MANAGEMENT

Management is responsible for the preparation and integrity of our financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States consistently applied, and necessarily include some amounts that are based on management's best estimates and judgment.

We maintain a system of internal accounting and administrative controls and an ongoing program of internal audits that management believes provide reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. Our financial statements have been audited by our independent accountants, PricewaterhouseCoopers LLP. In accordance with auditing standards generally accepted in the United States, the independent accountants obtained a sufficient understanding of our internal controls to plan their audit and determine the nature, timing, and extent of other tests to be performed.

The Audit Committee of the Board of Directors, composed solely of outside directors, meets with management, internal auditors, and PricewaterhouseCoopers LLP to review planned audit scopes and results and to discuss other matters affecting internal accounting controls and financial reporting. The independent accountants have direct access to the Audit Committee and periodically meet with the Audit Committee without management representatives present.

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and changes in shareholders' equity and comprehensive income (loss) present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 8 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivatives to adopt the requirements of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."

PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 5, 2003

STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2002	2001	2000
	(in thousands, except share/per share amounts)		
Operating revenues:			
Gas sales	\$ 198,108	\$ 248,952	\$ 200,269
Gas marketing	41,709	71,839	137,234
Oil sales	14,340	16,932	15,537
Gas transportation and other	7,345	7,204	10,843
	261,502	344,927	363,883
Operating costs and expenses:			
Gas purchases — utility	48,388	68,161	58,669
Gas purchases — marketing	37,927	68,010	133,221
Operating expenses	38,154	39,035	34,808
General and administrative expenses	26,446	25,073	24,982
Unusual items	—	—	111,288
Depreciation, depletion and amortization	53,992	52,899	45,869
Taxes, other than income taxes	10,090	9,080	8,515
	214,997	262,258	417,352
Operating income (loss)	46,505	82,669	(53,469)
Interest expense:			
Interest on long-term debt	21,664	23,920	24,089
Other interest charges	1,285	1,374	3,047
Interest capitalized	(1,483)	(1,595)	(2,447)
	21,466	23,699	24,689
Other income (expense)	(566)	(799)	1,997
Income (loss)before income taxes and minority interest	24,473	58,171	(76,161)
Minority interest in partnership	(1,454)	(930)	—
Income (loss)before income taxes	23,019	57,241	(76,161)
Provision (benefit)for income taxes			
Current	—	—	—
Deferred	8,708	21,917	(29,474)
	8,708	21,917	(29,474)
Net income (loss)	\$ 14,311	\$ 35,324	\$ (46,687)
Earnings (loss)per share:			
Basic	\$.57	\$ 1.40	\$ (1.86)
Diluted	.55	1.38	(1.86)
Weighted average common shares outstanding:			
Basic	25,226,580	25,198,105	25,043,586
Diluted	26,052,238	25,601,110	25,043,586

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

BALANCE SHEETS**Southwestern Energy Company and Subsidiaries**

	December 31,	
	2002	2001
	(in thousands)	
ASSETS		
Current assets		
Cash	\$ 1,690	\$ 3,641
Accounts receivable	42,115	42,763
Inventories, at average cost	24,735	26,606
Hedging asset — SFAS No.133	3,130	9,381
Regulatory asset — hedges	—	5,817
Other	4,468	4,996
Total current assets	76,138	93,204
Investments	15,287	15,538
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including \$25,494,000 in 2002 and \$21,102,000 in 2001 excluded from amortization	1,030,300	970,680
Gas distribution systems	197,473	192,784
Gas in underground storage	32,395	32,046
Other	31,391	30,110
	1,291,559	1,225,620
Less: Accumulated depreciation, depletion and amortization	659,398	605,790
	632,161	619,830
Other assets	16,576	14,551
	\$ 740,162	\$ 743,123

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

BALANCE SHEETS**Southwestern Energy Company and Subsidiaries**

	December 31,	
	2002	2001
	(in thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	\$ 29,881	\$ 41,644
Taxes payable	5,213	4,400
Interest payable	2,513	2,653
Customer deposits	4,999	4,845
Hedging liability — SFAS No.133	20,409	6,990
Regulatory liability — hedges	3,130	—
Over-recovered purchased gas costs	5,697	8,184
Other	2,715	2,752
Total current liabilities	74,557	71,468
Long-term debt	342,400	350,000
Other liabilities		
Deferred income taxes	116,591	122,381
Other	16,671	3,187
	133,262	125,568
Commitments and contingencies		
Minority interest in partnership	12,455	13,001
Shareholders' equity		
Common stock, \$0.10 par value; authorized 75,000,000 shares, issued 27,738,084 shares	2,774	2,774
Additional paid-in capital	19,130	19,764
Retained earnings	197,988	183,677
Accumulated other comprehensive income (loss)	(17,358)	5,763
	202,534	211,978
Less: Common stock in treasury, at cost, 1,793,456 shares in 2002 and 2,261,766 shares in 2001	19,981	25,196
Unamortized cost of restricted shares issued under stock incentive plan, 498,123 shares in 2002 and 416,537 shares in 2001	5,065	3,696
	177,488	183,086
	\$ 740,162	\$ 743,123

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

STATEMENTS OF CASH FLOWS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2002	2001	2000
		(in thousands)	
Cash flows from operating activities			
Net income (loss)	\$ 14,311	\$ 35,324	\$ (46,687)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	56,399	54,505	48,686
Deferred income taxes	8,708	21,917	(29,474)
Ineffectiveness of cash flow hedges	1,121	—	—
Equity in loss of NOARK partnership	251	1,484	1,767
Gain on sale of Missouri utility assets	—	—	(3,209)
Minority interest in partnership	(1,015)	(533)	—
Change in assets and liabilities:			
Accounts receivable	648	34,278	(36,693)
Income taxes receivable	—	—	85
Under/over-recovered purchased gas costs	(2,487)	21,126	(14,104)
Inventories	1,871	(9,606)	2,290
Accounts payable	(2,883)	(12,660)	22,156
Other current assets and liabilities	650	(1,252)	1,980
Net cash provided by (used in) operating activities	77,574	144,583	(53,203)
Cash flows from investing activities			
Capital expenditures	(92,062)	(106,060)	(75,717)
Sale of Missouri utility assets	—	—	32,000
Sale of natural gas and oil properties	26,415	—	13,651
Investment in NOARK partnership	—	(1,449)	(3,250)
(Increase) decrease in gas stored underground	(349)	(4,179)	845
Other items	1,527	826	(1,066)
Net cash used in investing activities	(64,469)	(110,862)	(33,537)
Cash flows from financing activities			
Payments on revolving long-term debt	(204,100)	(248,500)	(247,900)
Borrowings under revolving long-term debt	196,500	202,500	363,700
Change in bank drafts outstanding	(9,880)	—	—
Proceeds from exercise of common stock options	1,955	—	—
Retirement of notes and payments on long-term debt	—	—	(24,910)
Contribution from minority interest owner in partnership	469	13,534	—
Dividends paid	—	—	(3,004)
Net cash provided by (used in) financing activities	(15,056)	(32,466)	87,886
Increase (decrease) in cash	(1,951)	1,255	1,146
Cash at beginning of year	3,641	2,386	1,240
Cash at end of year	\$ 1,690	\$ 3,641	\$ 2,386

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

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

Southwestern Energy Company and Subsidiaries

	Common Stock		Additional Paid-In Capital	Retained Earnings	Treasury Stock	Unamortized Restricted Stock Awards	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount						
Balance at December31, 1999	27,738	\$ 2,774	\$ 20,732	\$ 198,044	\$ (30,083)	\$ (1,111)	\$ —	\$ 190,356
Net income	—	—	—	(46,687)	—	—	—	(46,687)
Issuance of restricted stock	—	—	(554)	—	1,720	(1,114)	—	52
Cancellation of restricted stock	—	—	42	—	(122)	80	—	—
Amortization of restricted stock	—	—	—	—	—	574	—	574
Cash dividends declared (\$0.12 per share)	—	—	—	(3,004)	—	—	—	(3,004)
Balance at December31, 2000	27,738	2,774	20,220	148,353	(28,485)	(1,571)	—	141,291
Comprehensive income:								
Transition adjustment for adoption of SFAS No.133	—	—	—	—	—	—	(36,963)	(36,963)
Net income	—	—	—	35,324	—	—	—	35,324
Change in value of derivatives	—	—	—	—	—	—	42,726	42,726
Total comprehensive income	—	—	—	—	—	—	—	41,087
Exercise of stock options	—	—	(31)	—	93	—	—	62
Issuance of restricted stock	—	—	(446)	—	3,247	(2,801)	—	—
Cancellation of restricted stock	—	—	21	—	(51)	30	—	—
Amortization of restricted stock	—	—	—	—	—	646	—	646
Balance at December31, 2001	27,738	2,774	19,764	183,677	(25,196)	(3,696)	5,763	183,086
Comprehensive income:								
Net income	—	—	—	14,311	—	—	—	14,311
Change in value of derivatives	—	—	—	—	—	—	(19,763)	(19,763)
Change in value of pension liability	—	—	—	—	—	—	(3,358)	(3,358)
Total comprehensive income (loss)	—	—	—	—	—	—	—	(8,810)
Exercise of stock options	—	—	(728)	—	2,683	—	—	1,955
Issuance of restricted stock	—	—	77	—	2,601	(2,678)	—	—
Cancellation of restricted stock	—	—	17	—	(69)	52	—	—
Amortization of restricted stock	—	—	—	—	—	1,257	—	1,257
Balance at December31, 2002	27,738	\$ 2,774	\$ 19,130	\$ 197,988	\$ (19,981)	\$ (5,065)	\$ (17,358)	\$ 177,488

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

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

Southwestern Energy Company and Subsidiaries

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	2002	2001	2000
	(in thousands)		
Balance, beginning of year	\$ 5,763	\$ —	\$—
Cumulative effect of adoption of SFAS No.133	—	(36,963)	—
Current period reclassification to earnings	4,735	22,874	—
Current period change in derivative instruments	(24,498)	19,852	—
Current period change in pension liability	(3,358)	—	—
Balance, end of year	\$ (17,358)	\$ 5,763	\$—

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries December 31, 2002, 2001 and 2000

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Consolidation

Southwestern Energy Company (Southwestern or the Company) is an integrated 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 activities are concentrated in Arkansas, Louisiana, Texas, New Mexico and Oklahoma. The gas distribution segment operates in northern Arkansas and, depending upon weather conditions and current supply contracts, can obtain greater than 50% of its gas supply from one of the Company's exploration and production subsidiaries. The customers of the gas distribution segment consist of residential, commercial and industrial users of natural gas. Southwestern's marketing and transportation business is concentrated in its core areas of operations.

The consolidated financial statements include the accounts of Southwestern Energy Company and its wholly-owned subsidiaries, Southwestern Energy Production Company (SEPCO), SEECO, Inc., Arkansas Western Gas Company, Southwestern Energy Services Company, Diamond "M" Production Company, Southwestern Energy Pipeline Company, and A.W. Realty Company. The consolidated financial statements also include the results for a limited partnership, Overton Partners, L.P., in which SEPCO is the sole general partner. All significant intercompany accounts and transactions have been eliminated. The Company accounts 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 (SFAS) 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.

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.

Unusual Items

In June 2000, the Company reported that the Arkansas Supreme Court ruled to affirm the 1998 decision of the Sebastian County Circuit Court awarding \$109.3 million in a class action to royalty owners of SEECO, Inc. (Hales judgment). The Company fully satisfied the judgment and the Circuit Court in Sebastian County issued an order in complete satisfaction of the judgment effective July 18, 2000. Additionally, the Company incurred an unusual charge of \$2.0 million during 2000 related to other litigation.

Property, Depreciation, Depletion and Amortization

Gas and Oil Properties. The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive)

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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. The Company excludes all costs of unevaluated properties from immediate amortization. The Company's unamortized costs of natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10percent plus the lower of cost or market value of any unproved properties. If the Company's unamortized costs in natural gas and oil properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At December31, 2002, the Company's net book value of natural gas and oil properties did not exceed the ceiling amount. Decreases in market prices from December31, 2002 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

In November 2002, the Company sold oil and gas properties for net proceeds of \$26.4million; the proceeds of the sale were reflected as a reduction of oil and gas properties with no gain or loss recognized.

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 1.8% to 5.8%.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 5 to 35years.

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.

Gas in Underground Storage. The Company has two gas storage facilities, both stated at average cost. The storage facility owned by the 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 exploration and production 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 gas prices that the Company expects to realize.

Capitalized Interest. Interest is capitalized on the cost of unevaluated gas and oil properties excluded from amortization. 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.

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 level included in the base 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.

The Company filed a rate increase request in November 2002 and expects the Arkansas Public Service Commission to rule on this request for a rate increase that would be effective no earlier than September 2003.

Gas Production Imbalances

The exploration and production 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

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gas sales are disproportionately allocated to owners because of marketing or other contractual arrangements. At December 31, 2002, the Company had overproduction of 1.3 Bcf valued at \$3.9 million and underproduction of 1.5 Bcf valued at \$4.3 million. At December 31, 2001, the Company had overproduction of 1.6 Bcf valued at \$4.3 million and underproduction of 1.7 Bcf valued at \$4.9 million.

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 carry forward at December 31, 2002 was \$117.2 million with an expiration date of December 31, 2020.

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 trading purposes. The Company uses commodity swap agreements and options to hedge sales and purchases of natural gas and sales of crude oil. Gains and losses resulting from hedging activities have been recognized in the statements of operations when the related physical transactions of commodities were recognized. Gains or losses from commodity swap agreements and options that do not qualify for accounting treatment as hedges would be recognized currently as other income or expense. See Note 8 for a discussion of the Company's hedging activities and the effects of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

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. The Company had options for 2,602,800 shares with an average exercise price of \$9.79 outstanding at December 31, 2000 that, due to the Company's net loss for 2000, would have had an anti-dilutive effect and were, therefore, not considered. The Company had options for 1,228,744 shares of common stock with a weighted average exercise price of \$13.36 per share at December 31, 2002, and options for 1,006,234 shares of common stock with a weighted average exercise price of \$13.83 per share at December 31, 2001, that were not included in the calculation of diluted shares because they would have had an anti-dilutive effect. The remaining 1,481,074 options at December 31, 2002 with a weighted average exercise price of \$7.53, and 1,665,952 options at December 31, 2001 with a weighted average exercise price of \$7.43 were included in the calculation of diluted shares.

Dividend on Common Stock

As a result of the adverse Hales judgment in June 2000, the Company has indefinitely suspended payment of quarterly dividends on its common stock. Additionally, at the present time the payment of dividends is prohibited under the Company's current revolving credit facility.

Loss on Retirement of Debt

During 2002, the Company adopted Statement of Financial Accounting Statement No. 145, "Revisions of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13, and Technical Corrections." Under the provisions of this standard, gains and losses from extinguishment of debt generally will no longer be classified as extraordinary items in the statement of operations. Accordingly, the Company's loss on early retirement of debt of \$1.5 million in the year ended December 31, 2000, which was previously presented as a net of tax extraordinary item, has been reclassified in the accompanying financial statements and presented as a component of interest expense. This reclassification had no impact on the Company's financial position, net income or cash flows.

Guarantees

During 2002, the Company adopted the disclosure provisions of Financial Accounting Standards Board Interpretation No.45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." The nature of the Company's guarantee of debt associated with its investment in NOARK is included in Note 7 and Note 11 to the financial statements.

Beginning in 2003, this accounting standard also requires that upon the issuance of guarantees, the guarantor must recognize a liability for the fair value of the obligations it assumes under the guarantee. Liability recognition is required on a prospective basis for guarantees that are made or modified after December 31, 2002. As the Company's issuance of guarantees is limited, the liability recognition provisions of the standard are not expected to have a material impact upon the Company's financial position or results of operations.

Accounting for Stock Based Compensation

At December 31, 2002, the Company has a stock-based employee compensation plan, which is described more fully in Note 9. The Company accounts for this plan under the recognition and measurement principles of APB Opinion No.25, "Accounting for Stock Issued to Employees," and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company does record compensation cost for the amortization of restricted stock shares issued to employees. The following table illustrates the effect on net income and earnings per share if the company had applied the fair value recognition provisions of FASB Statement No.123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	Year Ended December 31,		
	2002	2001	2000
Net income, as reported	\$ 14,311	\$ 35,324	\$ (46,687)
Add back: Amortization of restricted stock	781	399	352
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,798)	(1,350)	(1,109)
Pro forma net income	\$ 13,294	\$ 34,373	\$ (47,444)
Earnings per share:			
Basic-as reported	\$ 0.57	\$ 1.40	\$ (1.86)
Basic-pro forma	\$ 0.53	\$ 1.36	\$ (1.90)
Diluted-as reported	\$ 0.55	\$ 1.38	\$ (1.86)
Diluted-pro forma	\$ 0.51	\$ 1.34	\$ (1.90)

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: no dividend yield for all years; expected volatility of 45.6% for 2002, 46.4% for 2001 and 44.0% for 2000; risk-free interest rate of 3.4% for 2002, 4.8% for 2001 and 6.0% for 2000; and expected lives of 6 years for all option grants. The fair values of the option grants for each of the years 2002, 2001 and 2000 were \$1.9million, \$0.9million and \$2.6million, respectively.

Reclassifications

Certain amounts in the prior years' financial statements have been reclassified to conform with the 2002 presentation. These reclassifications had no impact on the Company's financial position, net income or cash flows.

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(2) DEBT

Debt balances as of December 31, 2002 and 2001 consisted of the following:

	2002	2001
	(in thousands)	
Senior notes:		
6.70% Series due 2005	\$ 125,000	\$ 125,000
7.625% Series due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Series due 2017	40,000	40,000
	225,000	225,000
Other:		
Variable rate (2.89% at December 31, 2002) unsecured revolving credit arrangements	117,400	125,000
Total long-term debt	\$ 342,400	\$ 350,000

In July 2001, the Company arranged a new unsecured revolving credit facility with a group of banks to replace an existing short-term credit facility that was put in place in July 2000. The revolving credit facility has a current capacity of \$125 million and a three-year term. The interest rate on the facility is 150 basis points over the current London Interbank Offered Rate (LIBOR). The credit facility contains covenants, which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 70% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 3.75 or higher through December 31, 2002. These covenants change over the term of the credit facility and generally become more restrictive. The Company was in compliance with its debt agreements at December 31, 2002. The Company has entered into interest rate swaps for calendar year 2003 that allow the Company to pay an average fixed interest rate of 3.8% (based upon current rates under the revolving credit facility) on \$40 million of its outstanding revolving debt.

There are no aggregate maturities of long-term debt for each of the years ending December 31, 2003, 2006 and 2007. For each of the years ended December 31, 2004 and 2005, the aggregate maturity is \$117.4 million and \$125.0 million, respectively. Total interest payments were \$21.5 million in 2002, \$24.4 million in 2001, and \$23.6 million in 2000.

(3) INCOME TAXES

The provision (benefit) for income taxes included the following components:

	2002	2001	2000
	(in thousands)		
Federal:			
Current	\$ —	\$ —	\$ —
Deferred	8,048	19,461	(24,202)
State:			
Current	—	—	—
Deferred	779	2,575	(5,153)
Investment tax credit amortization	(119)	(119)	(119)
Provision (benefit) for income taxes	\$ 8,708	\$ 21,917	\$ (29,474)

The provision (benefit) for income taxes was an effective rate of 37.8% in 2002, 38.3% in 2001, and 38.7% in 2000. The following reconciles the provision (benefit) for income taxes included in the consolidated statements of operations with the provision (benefit) which would result from application of the statutory federal tax rate to pre-tax financial income:

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	2002	2001	2000
	(in thousands)		
Expected provision (benefit)at federal statutory rate of 35%	\$ 8,055	\$ 20,034	\$ (26,656)
Increase (decrease)resulting from:			
State income taxes, net of federal income tax effect	506	1,674	(3,349)
Other	147	209	531
Provision (benefit)for income taxes	\$ 8,708	\$ 21,917	\$ (29,474)

The components of the Company's net deferred tax liability as of December 31, 2002 and 2001 were as follows:

	2002	2001
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	\$ 156,208	\$ 142,007
Stored gas	4,337	8,037
Prepaid pension costs	—	1,908
Book over tax basis in partnerships	11,324	11,148
Other	4,421	6,694
	176,290	169,794
Deferred tax assets:		
Accrued compensation	\$ 525	\$ 721
Alternative minimum tax credit carryforward	3,026	3,026
Accrued pension costs	2,102	—
Cash flow hedges — SFAS No.133	8,764	—
Net operating loss carryforward	45,952	41,922
Other	406	2,939
	60,775	48,608
Net deferred tax liability	\$ 115,515	\$ 121,186

There were no income tax payments in 2002 and 2001. Total income tax payments of \$0.5million were made in 2000. The Company's net operating loss carryforward at December31, 2002, was \$117.2million with an expiration date of December31, 2020. The Company also had an alternative minimum tax credit carryforward of \$3.0million and a statutory depletion carryforward of \$4.1 million at December31, 2002.

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(4)PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies SFAS No.132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets, and funded status as of December31, 2002 and 2001:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	\$ 60,925	\$ 56,571	\$ 2,099	\$ 2,011
Service cost	1,967	1,318	90	71
Interest cost	3,655	4,133	170	138
Actuarial loss (gain)	(6,762)	3,338	958	10
Benefits paid	(5,091)	(4,435)	(161)	(131)
Benefit obligation at December31	\$ 54,694	\$ 60,925	\$ 3,156	\$ 2,099
Change in plan assets:				
Fair value of plan assets at January 1	\$ 59,010	\$ 66,283	\$ 672	\$ 573
Actual return on plan assets	(11,959)	(2,478)	(7)	2
Employer contributions	13	18	228	228
Benefit payments	(5,091)	(4,435)	(161)	(131)
Amount transferred	—	(378)	—	—
Fair value of plan assets at December 31	\$ 41,973	\$ 59,010	\$ 732	\$ 672
Funded status:				
Funded status at December31	\$ (12,721)	\$ (1,916)	\$ (2,424)	\$ (1,427)
Unrecognized net actuarial (gain)loss	12,643	2,288	1,249	322
Unrecognized prior service cost	4,056	4,514	—	—
Additional minimum liability	(9,580)	—	—	—
Unrecognized transition obligation	—	—	860	946
Prepaid (accrued)benefit cost	\$ (5,602)	\$ 4,886	\$ (315)	\$ (159)

At December31, 2002, amounts recognized with respect to the Company's defined benefit pension plan included an accrued liability of \$5.6million, an intangible asset of \$4.1million and accumulated other comprehensive income of \$5.5million (\$3.4million after tax). Amounts recognized at December31, 2002 associated with the Company's other postretirement benefits was an accrued liability of \$.3million.

The Company's supplemental retirement plan has an accumulated benefit obligation in excess of plan assets. The plan's accumulated benefit obligation was \$374,000 and \$326,000 at December31, 2002 and 2001, respectively. There are no plan assets in the supplemental retirement plan due to the nature of the plan.

Net periodic pension and other postretirement benefit costs include the following components for 2002, 2001 and 2000:

	Pension Benefits			Other Postretirement Benefits		
	2002	2001	2000	2002	2001	2000
	(in thousands)					
Service cost	\$ 1,967	\$ 1,318	\$ 1,682	\$ 90	\$ 71	\$ 85
Interest cost	3,655	4,133	4,509	170	138	268
Expected return on plan assets	(5,165)	(5,829)	(6,190)	(41)	(34)	(39)
Amortization of transition obligation	—	(36)	(183)	86	86	103
Recognized net actuarial (gain)loss	7	(97)	(142)	79	19	63
Amortization of prior service cost	457	451	451	—	—	—
	\$ 921	\$ (60)	\$ 127	\$ 384	\$ 280	\$ 480

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The Company's pension plans provide for benefits on a "cash balance" basis. 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 weighted average assumptions used in the measurement of the Company's benefit obligations for 2002 and 2001 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.75 %	7.00 %	6.75 %	7.00 %
Expected return on plan assets	9.00 %	9.00 %	5.00 %	5.00 %
Rate of compensation increase	4.00 %	4.50 %	n/a	n/a

For measurement purposes, a 12% annual rate of increase in the per capita cost of covered medical benefits and a 7.5% annual rate of increase in the per capita cost of dental benefits was assumed for 2003. These rates were assumed to gradually decrease to 5% over seven years and remain at that level thereafter.

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%	1%
	Increase	Decrease
	(in thousands)	
Effect on the total service and interest cost components	\$ 26	\$ (32)
Effect on postretirement benefit obligation	\$ 369	\$ (315)

(5) NATURAL GAS AND OIL PRODUCING ACTIVITIES

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:

	2002	2001	2000
	(in thousands)		
Sales	\$ 122,207	\$ 153,937	\$ 110,920
Production (lifting) costs	(25,514)	(24,393)	(20,229)
Depreciation, depletion and amortization	(47,680)	(46,530)	(39,048)
	49,013	83,014	51,643
Income tax expense	(18,474)	(31,519)	(20,351)
Results of operations	\$ 30,539	\$ 51,495	\$ 31,292

The results of operations shown above exclude unusual items in 2000 and overhead and interest costs in all years. 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.

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The table below sets forth capitalized costs incurred in gas and oil property acquisition, exploration and development activities during 2002, 2001 and 2000:

	2002	2001	2000
	(in thousands)		
Proved property acquisition costs	\$ 3,481	\$ 7,323	\$ 7,428
Unproved property acquisition costs	4,984	4,482	5,941
Exploration costs	24,552	23,490	27,853
Development costs	51,818	63,103	27,519
Capitalized costs incurred	\$ 84,835	\$ 98,398	\$ 68,741
Amortization per Mcf equivalent	\$ 1.16	\$ 1.14	\$ 1.06

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized \$1.5million, \$1.6million and \$2.4 million during 2002, 2001 and 2000, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures.

In addition to capitalized interest, the Company also capitalized internal costs of \$9.5million, \$8.3million and \$7.3million during 2002, 2001 and 2000, 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 following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December31, 2002 and 2001:

	2002	2001
	(in thousands)	
Proved properties	\$ 1,004,806	\$ 944,502
Unproved properties	25,494	26,178
Total capitalized costs	1,030,300	970,680
Less: Accumulated depreciation, depletion and amortization	549,419	502,882
Net capitalized costs	\$ 480,881	\$ 467,798

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December31, 2002. Of the total, approximately \$13.5million is invested in Louisiana. The majority of Louisiana costs are related to seismic projects that will be evaluated over several years as the seismic data is interpreted and the acreage is explored. 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. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

	2002	2001	2000	Prior	Total
	(in thousands)				
Property acquisition costs	\$ 6,959	\$ 2,045	\$ 1,438	\$ 1,647	\$ 12,089
Exploration costs	3,821	635	1,722	3,931	10,109
Capitalized interest	426	289	734	1,847	3,296
	\$ 11,206	\$ 2,969	\$ 3,894	\$ 7,425	\$ 25,494

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(6)NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2002, 2001 and 2000:

	2002		2001		2000	
	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	355,813	7,704	331,754	8,130	307,523	7,859
Revisions of previous estimates	1,110	234	(21,598)	(979)	5,357	(22)
Extensions, discoveries, and other additions	73,803	553	77,187	1,272	53,389	1,347
Production	(35,972)	(682)	(35,477)	(719)	(31,602)	(676)
Acquisition of reserves in place	6,538	15	4,325	21	8,100	82
Disposition of reserves in place	(26,678)	(1,040)	(378)	(21)	(11,013)	(460)
Proved reserves, end of year	374,614	6,784	355,813	7,704	331,754	8,130
Proved, developed reserves:						
Beginning of year	281,461	6,429	270,830	7,100	250,290	7,154
End of year	286,276	5,633	281,461	6,429	270,830	7,100

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves" (standardized measure) is a disclosure required by SFAS No.69, "Disclosures About Oil and Gas Producing Activities." 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. with respect to 2002 and by K A Energy Consultants, Inc. with respect to 2001 and 2000.

Following is the standardized measure relating to proved gas and oil reserves at December31, 2002, 2001 and 2000:

	2002		2001		2000	
	(in thousands)					
Future cash inflows	\$	1,951,454	\$	1,095,843	\$	3,366,304
Future production costs		(466,742)		(313,357)		(461,808)
Future development costs		(62,206)		(57,136)		(44,609)
Future income tax expense		(420,336)		(182,103)		(974,273)
Future net cash flows		1,002,170		543,247		1,885,614
10% annual discount for estimated timing of cash flows		(500,571)		(235,087)		(990,472)
Standardized measure of discounted future net cash flows	\$	501,599	\$	308,160	\$	895,142

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. 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.

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Following is an analysis of changes in the standardized measure during 2002, 2001 and 2000:

	2002	2001	2000
		(in thousands)	
Standardized measure, beginning of year	\$ 308,160	\$ 895,142	\$ 262,075
Sales and transfers of gas and oil produced, net of production costs	(96,693)	(129,544)	(90,691)
Net changes in prices and production costs	284,277	(979,522)	837,691
Extensions, discoveries, and other additions, net of future production and development costs	137,105	102,832	259,212
Acquisition of reserves in place	11,269	5,406	33,032
Revisions of previous quantity estimates	4,870	(24,966)	20,178
Accretion of discount	39,451	133,136	38,076
Net change in income taxes	(106,177)	349,862	(317,527)
Changes in production rates (timing)and other	(80,663)	(44,186)	(146,904)
Standardized measure, end of year	\$ 501,599	\$ 308,160	\$ 895,142

(7) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

The Company holds a 25% general partnership interest in NOARK. NOARK Pipeline was formerly a 258-mile intrastate gas transmission system, which extended across northern Arkansas. In January 1998, the Company entered into an agreement with Enogex Inc. (Enogex) that resulted in the expansion of the NOARK Pipeline and provided the pipeline with access to Oklahoma gas supplies through an integration of NOARK with the Ozark Gas Transmission System (Ozark). Enogex is a subsidiary of OGE Energy Corp. Ozark was a 437-mile interstate pipeline system, which began in eastern Oklahoma and terminated in eastern Arkansas. Enogex acquired the Ozark system and contributed it to NOARK. Enogex also acquired the NOARK partnership interests not owned by Southwestern. The acquisition of Ozark and its integration with NOARK Pipeline was approved by the Federal Energy Regulatory Commission in late 1998 at which time NOARK Pipeline was converted to an interstate pipeline and operated in combination with Ozark. Enogex funded the acquisition of Ozark and the expansion and integration with NOARK Pipeline, which resulted in the Company's ownership interest in the partnership decreasing to 25% from 48%. The Company is responsible for 60% of debt principal and interest payments in accordance with its several guarantee of NOARK's debt.

The Company's investment in NOARK totaled \$15.2million at December31, 2002, and \$15.5million at December31, 2001 and 2000, including advances of \$1.4million made during 2001 and \$3.3million made during 2000. The Company did not advance any funds to NOARK during 2002. The prior advances were made primarily to service NOARK's long-term debt. See Note 11 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

The Company recorded pre-tax losses of \$0.3million, \$1.5million and \$1.8 million for 2002, 2001 and 2000, respectively, for its share of NOARK's results of operations. The Company records its share of NOARK's results of operations in other income (expense) on the consolidated statements of operations.

(8) 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:

Cash, Customer Deposits, and Short-Term Debt: 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 and Interest Hedges: The fair value of all hedging financial instruments is the amount at which they could be settled, based on quoted market prices or estimates obtained from dealers. The carrying amounts and estimated fair values of the Company's financial instruments as of December31, 2002 and 2001 were as follows:

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	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash	\$ 1,690	\$ 1,690	\$ 3,641	\$ 3,641
Customer deposits	4,999	4,999	4,845	4,845
Long-term debt	342,400	340,048	350,000	356,179
Commodity and interest hedges asset (liability)	(20,875)	(20,875)	3,246	3,246

Derivatives and Risk Management

SFAS No.133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No.137 and SFAS No.138, was adopted by the Company on January 1, 2001. SFAS No.133 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.

Upon adoption of SFAS No.133 on January 1, 2001, the Company recorded a transition obligation of \$60.6 million related to cash flow hedges in place that are intended to reduce the volatility in commodity prices for the Company's forecasted natural gas and oil production. At December 31, 2002, the Company recorded hedging assets of \$3.1 million, hedging liabilities of \$24.0 million, a regulatory liability of \$3.1 million related to its utility gas purchase hedges, and a net of tax loss to other comprehensive income (loss) of \$14.0 million. 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. The Company recorded \$1.1 million in 2002 related to basis differential ineffectiveness associated with the Company's cash flow hedges. There was no significant ineffectiveness recorded in 2001. Additionally, there were no discontinued hedges in 2002 or 2001. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the adoption of SFAS No.133.

The Company uses 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. The 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.

The Company uses over-the-counter natural gas and crude oil swap agreements and options to hedge sales of Company production, to hedge activity in its marketing segment, and to hedge the purchase of gas in its utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) 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 the Company pays to (production hedge) or receives from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

At December 31, 2002, the Company had outstanding natural gas price swaps on total notional volumes of 13.3 Bcf in 2003 and 7.2 Bcf in 2004 for which the Company will receive fixed prices ranging from \$2.75 to \$4.30 per MMBtu. Outstanding oil price swaps on 240 MBbls were in place that will yield the Company an average price of \$25.40 per barrel. At December 31, 2002, the Company also had outstanding natural gas price swaps on total notional gas purchase volumes of 2.7 Bcf in 2003 for which the Company will pay an average fixed price of \$3.42 per Mcf.

At December 31, 2002, the Company had collars in place on 15.9 Bcf in 2003 and 8.0 Bcf in 2004 of future gas production. The 15.9 Bcf in 2003 had an average floor and ceiling price of \$3.16 and \$4.84 per MMBtu, respectively. The 8.0 Bcf in 2004 had an average floor and ceiling price of \$3.50 and \$4.65 per MMBtu, respectively. The Company's price risk management activities reduced revenues by \$6.1 million in 2002, \$10.3 million in 2001 and \$39.3 million in 2000.

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The Company has outstanding interest rate swaps on a notional amount of \$40million. Under these contracts the Company will make average fixed interest payments at 2.3% and receive variable prices based on the one-month LIBOR rate. The Company currently pays an additional 1.5% above LIBOR on its revolving credit facility.

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.

(9)STOCK OPTIONS

The Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) was adopted in February 2000 and provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2000 Plan replaced 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 2000 Plan provides for grants of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock that in the aggregate do not exceed 1,250,000 shares. The types of incentives which may be awarded are comprehensive and are intended to enable the 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 2000 Plan.

The Southwestern Energy Company 2002 Employee Stock Incentive Plan (2002 Plan) was adopted in October 2002 and provides for the compensation of employees who are not officers or directors of the Company under provisions of Section 16 of the Securities Exchange Act of 1934. The 2002 Plan provides for grants of options, stock appreciation rights, shares of phantom stock and shares of restricted stock that in the aggregate do not exceed 300,000 shares.

The 1993 Plan provided for the compensation of officers and key employees of the Company and its subsidiaries 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 2000 Plan and the 1993 Plan to certain non-officer employees and to certain officers at the time of their hire.

The 2000 Plan awards each non-employee director who is eligible to participate in the plan an annual Director's Option with respect to 8,000 shares of common stock. Previously, the 1993 Director Plan provided for annual stock option grants of 12,000 shares (with 12,000 limited SARs) to each non-employee director.

The Company's 1985 Nonqualified Stock Option Plan expired in 1992, except with respect to awards then outstanding. The following tables summarize stock option activity for the years 2002, 2001 and 2000 and provide information for options outstanding at December 31, 2002:

	2002		2001		2000	
	Number	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Options outstanding at January 1	2,672,186	\$ 9.84	2,602,800	\$ 9.79	2,061,199	\$ 10.49
Granted	346,010	11.43	170,200	10.13	666,100	7.58
Exercised	247,464	8.39	11,252	7.00	—	—
Canceled	60,914	10.09	89,562	9.22	124,499	9.55
Options outstanding at December 31	2,709,818	\$ 10.17	2,672,186	\$ 9.84	2,602,800	\$ 9.79

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Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Options Outstanding at Year End	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at Year End	Weighted Average Exercise Price
\$6.00 - \$7.00	473,915	\$ 6.16	6.5	458,248	\$ 6.15
\$7.06 - \$8.75	721,759	7.41	7.4	532,396	7.40
\$8.76 - \$13.38	972,710	11.52	7.0	492,404	11.99
\$13.39 - \$17.50	541,434	14.94	2.4	509,653	14.97
	2,709,818	\$ 10.17		1,992,701	\$ 10.18

All options are issued at fair market value at the date of grant and expire ten years from the date of grant. Options generally vest to employees and directors over a three- to four-year period from the date of grant.

As disclosed in Note 1, the Company applies the disclosure-only provisions of SFAS No.123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans.

The Company granted 233,460 shares, 299,850 shares and 149,925 shares of restricted stock in 2002, 2001 and 2000, respectively. The fair values of the grants were \$2.7million for 2002, \$2.9million for 2001 and \$1.1million for 2000. Of the 986,475 shares granted to date, 433,715 shares vest over a three-year period, 510,210 shares vest over a four-year period, and the remaining shares vest over a five-year period. The related compensation expense is being amortized over the vesting periods. Compensation expense related to the amortization of restricted stock grants was \$1.3million for 2002 and \$0.6 million for both 2001 and 2000. As of December31, 2002, 441,331 shares have vested to employees and 47,021 shares have been canceled and returned to treasury shares.

(10)COMMON STOCK PURCHASE RIGHTS

In 1999, the Company's Common Share Purchase Rights Plan was amended and extended for an additional ten years. Per 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 \$40.00, 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 \$0.01 per right or exchanged for common shares 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.

(11)CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. The Company's share of the several guarantee is 60%. At December31, 2002 and 2001, the principal outstanding for these Notes was \$71.0million and \$73.0 million, respectively. The Notes

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were issued in June 1998 and require semi-annual principal payments of \$1.0 million. Under the several guarantee, the Company is required to fund its share of NOARK's debt service which is not funded by operations of the pipeline. As a result of the integration of NOARK Pipeline with the Ozark Gas Transmission System, as discussed further in Note 7, management of the Company believes that it will realize its investment in NOARK over the life of the system. Therefore, no provision for any loss has been made in the accompanying financial statements. Additionally, the Company's gas distribution subsidiary has transportation contracts for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system. These contracts expire in 2003 and are renewable year-to-year thereafter until terminated by 180days' notice.

The Company leases certain office space and vehicles under non-cancelable operating leases expiring through 2006. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At December 31, 2002, future minimum payments under non-cancelable leases accounted for as operating leases are \$729,000 in 2003; \$725,000 in 2004; \$703,000 in 2005; and \$496,000 in 2006. Total rent expense for all operating leases was \$811,000, \$706,000 and \$815,000 in 2002, 2001 and 2000, respectively.

Additionally, the Company's utility 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, 2002, future payments under these non-cancelable demand contracts are \$7,458,000 in 2003; \$1,821,000 in 2004; \$1,821,000 in 2005; \$1,656,000 in 2006; \$829,000 in 2007; and \$3,727,000 thereafter.

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.

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.

(12) SEGMENT INFORMATION

The Company applies SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information." The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of natural gas and crude oil. Revenues for the gas distribution segment arise from the transportation and sale of natural gas at retail. The marketing segment generates revenue through the marketing of both Company and third-party produced gas volumes.

Summarized financial information for the Company's reportable segments is shown in the following table. The "Other" column includes items not related to the Company's reportable segments including real estate, pipeline operations and corporate items.

	Exploration And Production	Gas Distribution	Marketing (in thousands)	Other	Total
2002					
Revenues from external customers	\$ 104,081	\$ 115,712	\$ 41,709	\$ —	\$ 261,502
Intersegment revenues	18,126	138	89,357	448	108,069
Operating income	36,048	7,563	2,652	242	46,505
Depreciation, depletion and amortization expense	47,680	6,115	104	93	53,992
Interest expense (1)	16,597	3,868	—	1,001	21,466
Provision (benefit) for income taxes (1)	6,744	1,316	963	(315)	8,708
Assets	527,591	163,803	9,998	38,770 (2)	740,162
Capital expenditures	85,201 (3)	6,115	—	746	92,062

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	Exploration And Production	Gas Distribution	Marketing (in thousands)	Other	Total
2001					
Revenues from external customers	\$ 126,006	\$ 147,082	\$ 71,839	\$ —	\$ 344,927
Intersegment revenues	27,931	200	118,486	448	147,065
Operating income	69,340	10,346	2,703	280	82,669
Depreciation, depletion and amortization expense	46,530	6,163	111	95	52,899
Interest expense (1)	18,238	4,413	34	1,014	23,699
Provision (benefit)for income taxes (1)	19,164	2,505	996	(748)	21,917
Assets	526,346	169,931	8,026	38,820 (2)	743,123
Capital expenditures	98,964 (3)	5,347	—	1,749	106,060
2000					
Revenues from external customers	\$ 75,597	\$ 151,052	\$ 137,234	\$ —	\$ 363,883
Intersegment revenues	35,323	182	70,514	448	106,467
Unusual items (4)	111,288	—	—	—	111,288
Operating income (loss)	(70,584)	14,655	2,460	—	(53,469)
Depreciation, depletion and amortization expense	39,048	6,625	109	87	45,869
Interest expense (1)	17,472	4,608	16	1,134	23,230
Provision (benefit)for income taxes (1)	(34,153)	4,869	912	(533)	(28,905)
Assets	460,296	188,811	20,929	35,342 (2)	705,378
Capital expenditures	69,211	5,994	24	488	75,717

- (1) Interest expense and the provision (benefit)for income taxes by segment are an allocation of corporate amounts as debt and income tax expense (benefit)are incurred at the corporate level.
- (2) Other assets include the Company's equity investment in the operations of NOARK (see Note 7), corporate assets not allocated to segments, and assets for non-reportable segments.
- (3) Includes \$0.5million in 2002 and \$13.5million in 2001 funded by the owner of the minority interest in Overton partnership.
- (4) Includes \$109.3million for the Hales judgment and \$2.0million for other litigation.

Intersegment sales by the exploration and production segment and marketing segment to the gas distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, prepaid debt costs, and prepaid and intangible pension related 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.

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(13) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2002 and 2001:

	Mar 31	June 30	Sept 30	Dec 31
	(in thousands, except per share amounts)			
2002				
Operating revenues	\$ 81,658	\$ 56,004	\$ 51,091	\$ 72,749
Operating income	16,839	8,900	7,994	12,772
Net income	6,715	1,770	1,274	4,552
Basic earnings per share	0.26	0.07	0.05	0.18
Diluted earnings per share	0.26	0.07	0.05	0.17
2001				
Operating revenues	\$ 137,129	\$ 76,023	\$ 59,396	\$ 72,379
Operating income	32,599	18,015	14,263	17,792
Net income	16,013	6,869	5,018	7,424
Basic earnings per share	0.64	0.27	0.20	0.29
Diluted earnings per share	0.63	0.27	0.20	0.29

(14) NEW ACCOUNTING STANDARDS

As previously disclosed, in July 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends FASB Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 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. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. Accordingly, this standard will become applicable to the Company in the first quarter of 2003. The effect of this standard on the Company's results of operations and financial condition at adoption is expected to include an increase in current and long-term liabilities of \$1.2 and \$5.5 million, respectively; a net increase in property, plant and equipment of \$5.4 million; a cumulative effect of adoption expense of \$0.8 million and a deferred tax asset of \$0.5 million. Subsequent to adoption, the Company does not expect this standard to have a material impact on the Company's financial position or its results of operations.

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of FAS 123" (FAS 148). The standard provides additional transition guidance for companies that elect to voluntarily adopt the accounting provisions of FAS 123, "Accounting For Stock-Based Compensation." FAS 148 does not change the provisions of FAS 123 that permit entities to continue to apply the intrinsic value method of APB 25, "Accounting for Stock Issued to Employees" (APB 25). As the Company applies APB 25, its accounting for stock-based compensation will not change as a result of FAS 148. FAS 148 does require certain new disclosures in both annual and interim financial statements. The required annual disclosures were effective immediately for the Company and have been included in Note 1 of the Company's financial statements. The new interim disclosure provisions will be effective for the Company in the first calendar quarter of 2003.

On January 17, 2003, the FASB issued FASB Interpretation No. 46 ("FIN 46"), Consolidation of Variable Interest Entities, an interpretation of ARB 51. The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE. This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. The Company does not expect the adoption of this standard to have any impact on its financial position or results of operations.

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

On June 20, 2002, our Board of Directors determined, upon the recommendation of its Audit Committee, to appoint PricewaterhouseCoopers LLP as our independent public accountants, replacing Arthur Andersen LLP, which we dismissed on the same date. This determination followed our decision, announced on March 29, 2002, to seek proposals from other independent public accountants to audit our financial statements for the fiscal year ended December 31, 2002.

The audit reports of Andersen on the consolidated financial statements of Southwestern and subsidiaries as of and for the fiscal years ended December 31, 2001 and December 31, 2000 did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty or audit scope. In addition, there were no modifications as to accounting principles except that the audit reports of Andersen contained an explanatory paragraph with respect to the change in the method of accounting for derivative instruments effective January 1, 2001 as required by the Financial Accounting Standards Board.

During our two most recent fiscal years ended December 31, 2001 and through June 20, 2002, there were no disagreements between us and Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to Andersen's satisfaction, would have caused Andersen to make reference to the subject matter of the disagreement in connection with their reports; and there were no reportable events, as described in Item 304(a) (1) (v) of Regulation S-K.

Southwestern provided Andersen with a copy of the foregoing disclosures and Andersen provided us with a letter dated June 20, 2002, stating that it had no basis for disagreement with such statements. This letter was filed as Exhibit 16.1 to a current report on Form 8-K dated June 20, 2002, filed by us with the SEC.

During our two most recent fiscal years and through June 20, 2002, we did not consult PricewaterhouseCoopers with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, or any other matters or reportable events listed in Items 304(a) (2) (i) and (ii) of Regulation S-K.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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 Shareholders on May 14, 2003, or the 2003 Proxy Statement, is hereby incorporated by reference for the purpose of providing information about the identification of our directors. We refer you to the sections "Election of Directors" and "Share Ownership of Management and Directors" in the 2003 Proxy Statement for information concerning our directors. Information concerning our executive officers is presented in Part I, Item 4 of this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The 2003 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation. We refer you to the section "Executive Compensation" in the 2003 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The 2003 Proxy Statement is hereby incorporated by reference for the purpose of providing information about security ownership of certain beneficial owners and our management. Refer to the sections "Security Ownership of Certain Beneficial Owners" and "Share Ownership of Management and Directors" for information about security ownership of certain beneficial owners and our management.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The 2003 Proxy Statement is hereby incorporated by reference for the purpose of providing information about related transactions. Refer to the section "Share Ownership of Management and Directors" and "Equity Compensation Plans" for information about transactions with our executive officers, directors or management.

ITEM 14. CONTROLS AND PROCEDURES

Within 90 days before filing this Form 10-K, our Chief Executive Officer and our Chief Financial Officer evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Our disclosure controls and procedures are the controls and other procedures that we designed to ensure that we record, process, summarize, and report in a timely manner the information we must disclose in reports that we file with the SEC. Our disclosure controls and procedures include our internal accounting controls. Based on the evaluation of our Chief Executive Officer and our Chief Financial Officer, our disclosure controls and procedures are effective. There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of our evaluation.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a)(1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent accountants 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.

(b) Current Reports on Form 8-K:

Date of Report	Item Number	Financial Statements Required to be Filed
January 24, 2003	7,9	No
December 4, 2002	7,9	No
November 20, 2002	5	No
November 14, 2002	7,9	No
November 12, 2002	7,9	No
October 30, 2002	7,9	No
October 25, 2002	7,9	No
October 18, 2002	7,9	No

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.

Dated: February 14, 2003

SOUTHWESTERN ENERGY COMPANY
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 14, 2003.

/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/ John Paul Hammerschmidt	John Paul Hammerschmidt	Director
/s/ Robert L. Howard	Robert L. Howard	Director
/s/ Kenneth R. Mourton	Kenneth R. Mourton	Director
/s/ Charles E. Scharlau	Charles E. Scharlau	Director

CERTIFICATION

I, Harold M. Korell, Chief Executive Officer of Southwestern Energy Company, certify that:

1. I have reviewed this annual report on Form 10-K of Southwestern Energy Company;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's independent accountants and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's independent accountants any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 14, 2003

/s/ Harold M. Korell

Harold M. Korell
Chief Executive Officer

CERTIFICATION

I, Greg D. Kerley, Chief Financial Officer of Southwestern Energy Company, certify that:

1. I have reviewed this annual report on Form 10-K of Southwestern Energy Company;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
 - (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
 - (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
 - (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's independent accountants and the audit committee of registrant's board of directors (or persons performing the equivalent function):
 - (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's independent accountants any material weaknesses in internal controls; and
 - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 14, 2003

/s/ Greg D. Kerley

Greg D. Kerley
Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
3.1*	Amended and Restated By-Laws of Southwestern Energy Company.
3.2	Amended and Restated Articles of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit4.2 to the Registrant's Registration Statement on FormS-3 (File No.333-101658) filed on December5, 2002)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit4.1 to the Registrant's FormS-3 (File No.333-101658)
4.2	Amended and Restated Rights Agreement between Southwestern Energy Company and the First Chicago Trust Company of New York dated April12, 1999. (Incorporated by reference to Exhibit4.1 to the Registrant's Annual Report on Form10-K (Commission File No.1-8246) for the year ended December31, 1999)
4.3	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 March15, 2002. (Incorporated by reference to Exhibit4.1 to the Registrant's Annual Report on Form10-K (Commission File No.1-8246) for the year ended December31, 2001)
4.4	Indenture, dated as of December1, 1995 between Southwestern Energy Company and The First National Bank of Chicago (now Bank One Trust Company, N.A.). (Incorporated by reference to Exhibit4 to Amendment No.1 to Registrant's Registration Statement on FormS-3 (File No.33-63895) filed on November17, 1995)
4.5	Credit Agreement dated July12, 2001 among Southwestern Energy Company, Bank One, N.A., Royal Bank of Canada, Fleet National Bank, Wells Fargo Bank Texas, N.A., Compass Bank and Hibernia National Bank, as lenders, Bank One, N.A. as administrative agent, Royal Bank of Canada, as syndication agent. (Incorporated by reference to Exhibit4.5 to the Registrant's Annual Report filed on Form10-K (Commission File No.1-8246) for the year ended December31, 2001)
10.1*	Consulting Agreement between Southwestern Energy Company and Charles E. Scharlau, dated May15, 2002.
10.2	Form of Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit10.20 of the Registrant's Annual Report on Form10-K (Commission File No.1-8246) for the year ended December31, 1991)
10.3	Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February17, 1999. (Incorporated by reference to Exhibit10.12 of the Registrant's Annual Report on Form10-K (Commission File No.1-8246) for the year ended December31, 1998)
10.4	Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit10.2(b) to the Registrant's Annual Report on Form10-K (Commission File No. 1-8246) for the year ended December31, 1998)
10.5	Southwestern Energy Company 2000 Stock Incentive Plan dated February18, 2000. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No.1-8246) for the 2000 Annual Meeting of Shareholders)

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Exhibit Number	Description
10.6	Southwestern Energy Company Supplemental Retirement Plan, amended as of February 1, 1996. (Incorporated by reference to Exhibit 10.5 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-8246) for the year ended December 31, 1995)
10.7	Southwestern Energy Company Supplemental Retirement Plan Trust, dated December 30, 1993. (Incorporated by reference to Exhibit 10.6 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-8246) for the year ended December 31, 1993)
10.8	Southwestern Energy Company Non-Qualified Retirement Plan, effective October 4, 1995. (Incorporated by reference to Exhibit 10.7 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-8246) for the year ended December 31, 1995)
10.9	Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated January 12, 1998. (Incorporated by reference to Exhibit 10.7 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-8246) for the year ended December 31, 1997)
10.10	Amendment No. 1 to the Amended and Restated Limited Partnership Agreement of NOARK Pipeline System, Limited Partnership dated June 18, 1998. (Incorporated by reference to Exhibit 10.14 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-8246) for the year ended December 31, 1998)
10.11*	Southwestern Energy Company 2002 Employee Stock Incentive Plan, effective October 23, 2002.
10.12*	Southwestern Energy Company 2002 Performance Unit Plan, effective December 11, 2002.
10.13*	Purchase and Sale Agreement by and between Southwestern Energy Production Company, as Seller, and Dutch Petroleum, LLC, as Buyer, dated November 5, 2002 relating to the sale of the Mid-Continent properties.
21.1*	List of Subsidiaries
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell Associates, Inc.
23.3*	Consent of KA Energy Consultants, Inc.

* Filed herewith

SOUTHWESTERN ENERGY COMPANY

BY-LAWS

* * * * *

ARTICLE I

STOCKHOLDERS

SECTION 1. The place for holding all meetings of stockholders shall be the office of the Corporation in the City of Fayetteville, State of Arkansas, or at such other place or places as shall be decided upon from time to time by the Board of Directors of the Corporation. The presiding officer, who shall conduct all stockholder meetings, shall be the Chairman of the Board or in the absence of a Chairman of the Board shall be the President, or in the absence of the President a member of the Board of Directors selected by the other members of the Board of Directors. At any meeting requiring a vote of the stockholders for the election of directors or for any other purpose requiring a ballot and vote by the stockholders there shall be two judges of election, appointed by the Chairman of the meeting, who shall take an oath of office to faithfully perform their duties. The judges of election shall canvass the meeting, determine the number of stockholders present in person and by proxy and determine if a quorum is present. It shall be the duty of the judges of election to examine, validate and tabulate the proxies voted and the votes cast in person. Upon completion of the tabulation, their report shall be read to the meeting and the results of such elections then formally declared by the Chairman of the meeting.

SECTION 2. VOTING: Stockholders having the right to vote shall be entitled to vote at meetings either in person or by proxy appointed by instrument in writing subscribed by the stockholder or by his duly authorized attorney. Such stockholder shall be entitled to one vote for each share of stock having voting power registered in his name on the books of the Company.

A complete list of the stockholders entitled to vote at any election of directors, arranged in alphabetical order with the address of each and the number of voting shares held by each, shall be prepared by the Secretary and be available for inspection at the Company's principal office or at a place identified in the meeting notice in the city where the meeting will be held. The stockholder list shall be available for inspection at all time during the usual hours for business beginning two (2) business days after notice of the meeting is given for which the list was prepared and continuing through the meeting.

SECTION 3. QUORUM: Except as provided in the next section hereof, any number of stockholders together holding at least a majority of the stock issued and outstanding and entitled to vote thereat, who shall be present in person or represented by proxy at any meeting duly called, shall constitute a quorum for the transaction of business.

SECTION 4. ADJOURNMENT OF MEETING: If less than a quorum shall be in attendance at any time for which the meeting shall have been called, the meeting may, after the lapse of at least half an hour, be adjourned from time to time by a majority vote of the stockholders present or represented and entitled to vote thereat. If notice of such adjourned meeting is sent to the stockholders entitled to receive the same, such notice also containing a statement of the purpose of the meeting and that the previous meeting failed for lack of a quorum, and that under the provisions of this Section it is proposed to hold the adjourned meeting with a quorum of those present, then any number of stockholders, in person or by proxy, shall constitute a quorum at such meeting unless otherwise provided by statute.

SECTION 5. ANNUAL ELECTION OF DIRECTORS: The annual meeting of stockholders for the election of directors and the transaction of other business shall be held on such date and at such time as may be determined by the Board of Directors from time to time. At each annual meeting, the stockholders entitled to vote thereat shall by plurality vote by ballot elect a Board of Directors, and they may also transact such other corporate business as shall be stated in the notice of meeting.

Only persons who are nominated in accordance with the following procedures shall be eligible for election as directors. Nominations of persons for election to the Board of Directors of the Company may be made at a meeting of stockholders by or at the direction of the Board of Directors, by any nominating committee or person appointed by the Board of Directors, or by any stockholder of the Company entitled to vote for the election of directors at the meeting who has complied with the notice procedures set forth in this Section 5 of Article I. Such nominations, other than those made by or at the direction of the Board of Directors, shall be made pursuant to timely notice in writing to the secretary of the Company. To be timely, a stockholder's notice shall be delivered to or mailed and received at the principal executive offices of the Company not less than 50 nor more than 75 days prior to the meeting date; provided, however, that in the event that less than 65 days' notice of the meeting date is given to stockholders, notice by the stockholder must be so received no later than the close of business on the 15th day following the day on which notice of the meeting date was mailed. Such stockholder's notice shall set forth (a) as to each nominee whom the stockholder proposes to nominate for election or reelection as a director, (i) the name, age, business address and residence address of the nominee, (ii) the principal occupation or employment of the nominee, (iii) the class and number of shares of capital stock of the Company which are beneficially owned by the nominee and (iv) any other information relating to the nominee that is required to be disclosed in solicitations for proxies for election of directors pursuant to Schedule 14A under the Securities Exchange Act of 1934, as amended; and (b) as to the stockholder giving the notice, (i) the name and record address of the stockholder and (ii) the class and number of shares of capital stock of the Company that are beneficially owned by the stockholder. The Company may require any proposed nominee to furnish such other information as may reasonably be required by the Company to determine the eligibility of such proposed nominee to serve as a director of the Company. The presiding officer of the meeting shall, if the facts warrant, determine that a nomination was not made in accordance with the foregoing procedure, and if he should so determine, he may so declare to the meeting and the defective nomination shall be disregarded.

At any meeting of stockholders, only such business shall be conducted as shall have been properly brought before the meeting. For business to be properly brought before a meeting by a stockholder, the stockholder must have given timely notice thereof to the secretary of the Company. To be timely, such notice must be delivered to or mailed and received at the principal executive offices of the Company not less than 50 nor more than 75 days prior to the meeting date; provided, however, that in the event that less than 65 days' notice of the meeting date is given to stockholders, notice by the stockholder must be so received no later than the close of business on the 15th day following the day on which notice of the meeting date was mailed. Such stockholder's notice shall set forth as to each matter the stockholder proposes to bring before the meeting: (i) a brief description of the business desired to be brought before the meeting and the reasons for conducting such business at the meeting, (ii) the name and address of the stockholder proposing such business, (iii) the class and number of shares of capital stock of the Company that are beneficially owned by such stockholder and (iv) any material interest of such stockholder in such business. The presiding officer of the meeting shall, if the facts warrant, determine that business was not properly brought before the meeting in accordance with the foregoing procedure and, if he should so determine, he may so declare to the meeting and any such business not properly brought shall not be transacted. Notwithstanding the provisions of this paragraph, so long as the Company is subject to Rule 14a-8 under the Securities Exchange Act of 1934, as amended, business consisting of a proposal properly included in the Company's proxy statement with respect to a meeting pursuant to such Rule may be transacted at a meeting.

SECTION 6. SPECIAL MEETING – HOW CALLED: Special meetings of the stockholders for any purpose or purposes may be called by the President or Secretary, and shall be called upon a resolution in writing therefor, stating the purpose or purposes thereof, delivered to the President or Secretary, signed by two directors or by at least ten percent (10%) of the stockholders entitled to vote, or by resolution of the directors.

The record date for determining stockholders entitled to request a special meeting shall be fixed by the Board of Directors of the Company. Any stockholder seeking to request a special meeting shall, by written notice, request the Board of Directors to fix a record date. The Board of Directors shall, upon receipt of such a request, fix the record date in accordance with Section 4-27-707 of the Arkansas Business Corporation Act of 1987 (the "ABCA"). If the record date falls on a Saturday, Sunday or legal holiday, the record date shall be the day next following which is not a Saturday, Sunday or legal holiday.

SECTION 7. MANNER OF VOTING AT STOCKHOLDERS MEETINGS: At all meetings of stockholders all questions, except as otherwise expressly provided by statute or by these By-Laws, shall be determined by a majority vote of the stockholders present in person or represented by proxy and entitled to vote; provided, however, that any qualified voter may demand a vote by ballot, and in that case, such vote shall immediately be taken.

SECTION 8. NOTICE OF STOCKHOLDERS MEETING: Written or printed notice, stating the place and time of the meeting, shall be given by the Secretary to each stockholder entitled to vote thereat at his last known post office address, at least ten (10) days before the

meeting in the case of an annual meeting and five (5) days before the meeting in the case of a special meeting.

SECTION 9. SPECIFIC POWERS OF STOCKHOLDERS: The directors in their discretion may submit any contract or act for approval or ratification at any annual meeting of the stockholders or at any meeting of the stockholders called for the purpose of considering any such act or contract, and any contract or act that shall be approved or be ratified by the vote of the holders of a majority of the capital stock of the Corporation which is represented in person or by proxy at such meeting (provided that a lawful quorum of stockholders be there represented in person or by proxy) shall be as valid and as binding upon the Corporation and upon all the stockholders, as though it had been approved or ratified by every stockholder of the Corporation, whether or not the contract or act would otherwise be open to legal attack because of directors' interest, or for any other reason.

SECTION 10. ACTION WITHOUT MEETING:

(a) Notice of Action by Written Consent. Prompt notice of the taking of any action without a meeting pursuant to Section 4-27-704 of the Arkansas Business Corporation Act of 1987 (the "ABCA"), by less than unanimous written consent, shall be given to those stockholders who have not consented in writing.

(b) Record Date. The record date for determining stockholders entitled to express consent to an action in writing without a meeting shall be fixed by the Board of Directors of the Company. Any stockholder seeking to have the stockholders authorize or take action by written consent without a meeting shall, by written notice, request the Board of Directors to fix a record date. The Board shall, upon receipt of such a request, fix the record date in accordance with Section 4-27-707 of the ABCA. If the record date falls on a Saturday, Sunday or legal holiday, the record date shall be the day next following which is not a Saturday, Sunday or legal holiday.

(c) Date of Consent. The date for determining if an action has been consented to by the holder or holders of shares having requisite voting power to authorize or take the action specified therein (the "Consent Date") shall be the close of business on the 31st day after the later of (x) the record date fixed pursuant to paragraph (b) of this Section 10 and (y) the date on which materials soliciting consents are mailed to stockholders if such materials are required to be mailed under applicable law. If the Consent Date falls on a Saturday, Sunday or legal holiday, the Consent Date shall be the day next following which is not a Saturday, Sunday or legal holiday. On or prior to the Consent Date, consents may be revoked by written notice (i) to the Company, (ii) to the stockholder or stockholders soliciting consents or soliciting revocations in opposition to action by consent proposed by the Company (the "Soliciting Stockholders"), or (iii) to a proxy solicitor or other agent designated by the Company or the Soliciting Stockholder.

(d) Procedures. In the event of the delivery to the Company of a written consent or consents purporting to authorize or take action and/or related revocations (each such written consent and related revocation being referred to in this Section 10 as a "Consent"), the

Secretary of the Company shall provide for the safekeeping of such Consent and, as soon as practicable after the Consent Date, shall conduct such reasonable investigation as he deems necessary or appropriate for the purpose of ascertaining the validity of such Consent and all matters incident thereto, including, without limitation, whether the holders of shares having the requisite voting power to authorize or take the action specified in the Consent have given consent; provided, however, that if the action to which the Consent relates is the removal or replacement of one or more members of the Board, the Secretary of the Company shall designate two persons, who may not be members of the Board or otherwise affiliated with the Company, or a firm of nationally recognized independent inspectors of election, to serve as Inspectors with respect to such Consent and such Inspectors shall discharge the functions of the Secretary of the Company under this paragraph (d). If after such investigation the Secretary or the Inspectors (as the case may be) shall determine that the Consent is valid, that fact shall be certified on the records of the Company kept for the purpose of recording the proceedings of meetings of stockholders, and the Consent shall be filed in such records, at which time the Consent shall become effective as stockholder action as of the fifth business day following such certification.

ARTICLE II

DIRECTORS

SECTION 1. FIRST MEETING: The newly elected directors may hold their first meeting for the purpose of organization and the transaction of business, if a quorum be present, immediately after the annual meeting of the stockholders; or the time and place of such meeting may be fixed by consent in writing of all the directors.

SECTION 2. ELECTION OF OFFICERS: At such meeting the directors may elect a Chairman of the Board and shall elect a President from their number, one or more Vice Presidents, a Secretary and a Treasurer, who need not be directors. Such officers shall hold office until the next annual election of officers and until their successors are elected and qualify. In case such officer shall not be elected at such first meeting, they may be chosen at any subsequent meeting of directors called for the purpose.

SECTION 3. REGULAR MEETINGS: Regular meetings of the directors may be held without notice at such place, either within or without the State of Arkansas, and at such time as shall be determined from time to time by resolution of the directors.

SECTION 4. SPECIAL MEETINGS – HOW CALLED – NOTICE: Special meetings of the Board may be called by the President or by the Secretary on the written request of any two directors upon notice given to each director by letter delivered at least two days before the meeting or by telegram delivered at least one day before the meeting or by such shorter telephone or other notice as the person or persons calling the meeting may deem appropriate in the circumstances.

SECTION 5. NUMBER, QUORUM, QUALIFICATIONS AND RETIREMENT:

(a)The Board of Directors shall consist of not less than six (6)nor more than eight (8)members, as established by resolution of the Board of Directors. A majority of the directors shall constitute a quorum for the transaction of business. Directors need not be stockholders.

(b)Retired directors may be appointed to the position of director emeritus by the unanimous vote of the board or after having 20years of service and shall be invited, but not required, to attend the Annual Meeting of the Company and shall be available for consultation with management as required.

(i)Only existing non-employee members of the board of directors are eligible to become directors emeriti. Employee members of the board of directors will become eligible for the position of director emeritus after their employee status has ended. Any director becoming a director emeritus is no longer eligible for election as a director. A director emeritus may resign at any time.

(ii)A director emeritus shall continue to receive an annual fee of \$2,000 for the remainder of his life and such health care benefits as the Company provides to its full time employees.

SECTION 6. PLACE OF MEETING: The directors may hold their meetings and have one or more offices, and keep the books of the Company outside the State of Arkansas, at any office or offices of the Company, or at any other place as they may from time to time by resolution determine; provided, however, that a duplicate stock ledger shall always be kept at the principal office in Arkansas.

SECTION 7. GENERAL POWERS OF DIRECTORS: The Board of Directors shall have the management of the business of the Company, and subject to the restrictions imposed by law, by the Certificate of Incorporation, or by these By-Laws, may exercise all the powers of the Corporation.

SECTION 8. SPECIFIC POWERS OF DIRECTORS: Without prejudice to such general powers it is hereby expressly declared that the directors shall have the following powers, to wit:

(To adopt and alter a common seal of the Corporation.

1
)

(To make and change regulations, not inconsistent with these By-Laws, for the management of the Company's business and affairs.

2
)

(To purchase or otherwise acquire for the Company any property, rights or privileges which the Company is authorized to acquire.

3
)

(To pay for any property purchased for the Company either wholly or partly in money, stock, bonds, debentures or other securities of the
4 Company.
)

(To borrow money and to make and issue notes, bonds and other negotiable and transferable instruments, mortgages, deeds of trust and
5 trust agreements, and to do every act and thing necessary to effectuate the same.
)

(To remove any officer for cause, or any officer other than the President summarily without cause, and in their discretion, from time to
6 time, to devolve the powers and duties of any officer upon any other person for the time being.
)

(To appoint and remove or suspend such subordinate officers, agents or factors, as they may deem necessary, and to determine their
7 duties, and fix and, from time to time, change their salaries or remuneration, and to require security as and when they think fit.
)

(To confer upon any officer of the Company the power to appoint, remove and suspend subordinate officers, agents and factors.
8
)

(To determine who shall be authorized on the Company's behalf to make and sign bills, notes, acceptances, endorsements, checks,
9 releases, receipts, contracts and other instruments.
)

(To determine who shall be entitled to vote in the name and behalf of the Company, or to assign and transfer, any shares of stock, bonds,
1 or other securities of other corporations held by the Company.
0
)

(To delegate any of the powers of the Board in relation to the ordinary business of the Company to any standing or special committee, or
1 to any officer, or agent (with power of subdelegate), upon such terms as they think fit.
1
)

(To call special meetings of the stockholders for any purpose or purposes.
1
2
)

(To submit any contract or act for authorization or ratification by the stockholders in the manner and with the effect provided in Section9
1 of ArticleI.
3
)

SECTION 9. COMPENSATION OF DIRECTORS: By resolution of the Board, the directors may be paid their expenses of attendance and may be paid a fixed fee for attendance at each meeting of the Board of Directors or a stated fee as director. Unless otherwise prohibited by applicable law or listing standards, no such payment or anything herein contained shall preclude any director from serving the Company in any other capacity as an officer, attorney, agent or otherwise and receiving compensation therefor.

ARTICLE III

EXECUTIVE COMMITTEE

SECTION 1. HOW APPOINTED: The directors may appoint from their number an executive committee which may make its own rules of procedure and shall meet where and as provided by such rules, or by a resolution of the directors. A majority shall constitute a quorum, and in every case the affirmative vote of a majority of all the members of the committee shall be necessary to the adoption of any resolution.

SECTION 2. POWERS: During the intervals between the meetings of the directors the executive committee shall have and may exercise all the powers of the directors in the management of the business and affairs of the Company, including power to authorize the seal of the Company to be affixed to all papers which may require it, in such manner as such committee shall deem best for the interests of the Company, in all cases in which specific directions shall not have been given by the directors.

ARTICLE IV

OFFICERS

SECTION 1. The officers of the Company may be a Chairman of the Board, which office may be filled by resolution of the Board of Directors, and shall be a President, one or more Vice Presidents, one or more of whom may be designated as Executive Vice President and shall have senior authority, a Secretary, a Treasurer, and such assistants and other officers as may from time to time be elected or appointed by the Board of Directors. Two or more offices may be held by the same person.

SECTION 2. CHAIRMAN OF THE BOARD OF DIRECTORS: The Chairman of the Board of Directors shall preside at all meetings of the stockholders and of the Board of Directors; and by virtue of his office shall be a member of the executive committee. He shall have supervision of such matters as may be designated to him by the Board of Directors or the executive committee.

SECTION 2-A. VICE CHAIRMAN OF THE BOARD OF DIRECTORS: The Vice Chairman of the Board of Directors shall be vested with all the powers and shall perform all the duties of the Chairman in the absence or disability of the latter unless or until the Board of Directors shall otherwise determine. He shall have such other powers and perform such other duties as shall be prescribed by the Board of Directors.

SECTION 3. PRESIDENT: The President shall, in the absence of a Chairman of the Board, preside at all meetings of the directors, and act as Chairman at, and call to order all meetings of the stockholders; and he shall have power to call special meetings of the stockholders and directors for any purpose or purposes, appoint and discharge, subject to the approval of the directors, employees and agents of the Corporation and fix their compensation, make and sign contracts and agreements in the name and behalf of the Corporation, except that he be not authorized to dispose or encumber material assets of the

Corporation without the authority of the Board of Directors, and while the directors and/or committees are not in session he shall have general management and control of the business and affairs of the Corporation; he shall see that the books, reports, statements and certificates required by the statute under which this Corporation is organized or any other laws applicable thereto are properly kept, made and filed according to law; and he shall generally do and perform all acts incident to the office of President, or which are authorized or required by law.

SECTION 4. VICE PRESIDENTS: The Vice Presidents in the order of their seniority shall be vested with all the powers and shall perform all the duties of the President in the absence or disability of the latter, unless or until the directors shall otherwise determine. They shall have such other powers and perform such other duties as shall be prescribed by the directors.

SECTION 5. SECRETARY: The Secretary shall give, or cause to be given, notice of all meetings of the stockholders and directors, and all other notices required by law or by these By-Laws, and in case of his absence or refusal or neglect so to do, any such notice may be given by any person thereunto directed by the President, or by the directors or stockholders upon whose requisition the meeting is called as provided in these By-Laws. He shall record all proceedings of the meetings of the Corporation and of the directors in a book to be kept for that purpose, and shall perform such other duties as may be assigned to him by the directors or the President. He shall have custody of the seal of the Company and shall affix the same to all instruments requiring it, when authorized by the directors or the President, and attest the same. He shall be sworn to the faithful discharge of his duties.

SECTION 6. ASSISTANT SECRETARY: The Assistant Secretary shall be vested with the powers and shall perform all the duties of Secretary in the absence or disability of the latter, unless or until the directors shall otherwise determine. He shall have such other powers and perform such other duties as shall be prescribed by the directors.

SECTION 7. TREASURER: The Treasurer shall have the custody of all funds, securities, evidences of indebtedness and other valuable documents of the Company; he shall receive and give or cause to be given receipts and acquittances for moneys paid in on account of the Company and shall pay out of the funds on hand all just debts of the Company of whatever nature upon maturity of the same; he shall enter or cause to be entered in books of the Company to be kept for that purpose full and accurate accounts of all monies received and paid out on account of the Company, and, whenever required by the President or the Board of Directors, he shall render a statement of his cash accounts. He shall, unless otherwise determined by the Board of Directors, have charge of the original stock books, transfer books and stock ledgers and act as transfer agent in respect of the stock and securities of the Company; he shall prepare and submit from time to time to the Board of Directors financial, cash and operating budgets or estimates; he shall prepare and submit such other financial data and information as he shall be directed to by the Board of Directors; and he shall perform all of the other duties incident to the office of Treasurer. He shall give the Company a bond for the faithful discharge of his duties in such amount and with such surety as the Board of Directors shall prescribe.

SECTION 8. ASSISTANT TREASURER: The Assistant Treasurer shall be vested with all the powers and shall perform all the duties of Treasurer in the absence or disability of the latter, unless or until the directors shall otherwise determine. He shall have such other powers and perform such other duties as shall be prescribed by the directors.

SECTION 9. CONTROLLER: The Corporate Controller shall be responsible for directing the Corporation's accounting functions. Specific areas include the development and maintenance of planning and budgeting systems, analysis and interpretation of trends requiring management's attention, the preparation of financial and management reports and procedures, and senior management. Ancillary responsibilities include the supervision of external auditors, and participation in the planning and execution of the utility rate cases.

ARTICLE V

RESIGNATIONS: FILLING OF VACANCIES: INCREASE OF NUMBER OF DIRECTORS

SECTION 1. RESIGNATIONS: Any director, member of a committee or other officer may resign at any time. Such resignation shall be made in writing and shall take effect at the time specified therein, and if no time be specified, at the time of its receipt by the President or Secretary. The acceptance of a resignation shall not be necessary to make it effective.

SECTION 2. FILLING OF VACANCIES: If the office of any director, member of a committee or other office becomes vacant, the directors in office may appoint any qualified person to fill such vacancy, who shall hold office for the unexpired term and until his successor shall be duly chosen.

SECTION 3. INCREASE OF NUMBER OF DIRECTORS: The number of directors may be increased at any time by the affirmative vote of a majority of the directors, (or, by the affirmative vote of a majority in interest of the stockholders), at a special meeting called for that purpose, and by like vote the additional directors may be chosen at such meeting to hold office until the next annual election and until their successors are elected and qualify.

ARTICLE VI

CAPITAL STOCK

SECTION 1. ISSUE OF CERTIFICATES OF STOCK: The President shall cause to be issued to each stockholder one or more certificates, under the seal of the Company, signed by the President or Vice President and the Treasurer or Assistant Treasurer, or Secretary or Assistant Secretary, certifying the number of shares owned by him in the Company; provided, when any such certificate is signed by a transfer agent or registrar, the signature of any officer of the Company or its corporate seal, or both such signatures and seal, may be facsimiles engraved or printed.

SECTION 2. LOST CERTIFICATES: A new certificate of stock may be issued in the place of any certificate theretofore issued by the Corporation, alleged to have been lost or destroyed, and the directors may, in their discretion, require the owner of the lost or destroyed certificate, or his legal representatives, to give the Corporation a bond, in such sum as they may direct, not exceeding double the value of the stock, to indemnify the Company against any claim that may be made against it on account of the alleged loss of any such certificate or the issuance of any such new certificate.

SECTION 3. TRANSFER OF SHARES: The shares of stock of the Company shall be transferable only upon its books by the holders thereof in person or by their duly authorized attorneys or legal representatives, and upon such transfer the old certificates shall be surrendered to the Company by the delivery thereof to the person in charge of the stock and transfer books and ledgers, or to such other person as the directors may designate, by whom they shall be cancelled, and new certificates shall thereupon be issued. A record shall be made of each transfer and whenever a transfer shall be made for collateral security, and not absolutely, it shall be so expressed in the entry of the transfer.

SECTION 4. CLOSING OF TRANSFER BOOKS: The Board of Directors shall have power to close the stock transfer books of the Corporation for a period not exceeding twenty (20) days preceding the date of any meeting of stockholders or the date for payment of any dividend or the date for the allotment of rights or the date when any change or conversion or exchange of capital stock shall go into effect; provided, however, that in lieu of closing the stock transfer books as aforesaid, the Board of Directors may fix in advance a date, not exceeding sixty-five (65) days preceding the date of any meeting of stockholders or the date for the payment of any dividend, or the date for the allotment of rights, or the date when any change or conversion or exchange of capital stock shall go into effect, as a record date for the determination of the stockholders entitled to notice of, and to vote at, any such meeting, or entitled to receive payment of any such dividend or to any such allotment of rights, or to exercise the rights in respect of any such change, conversion or exchange of capital stock, and in such case such stockholders only as shall be stockholders of record on the date so fixed shall be entitled to such notice of, and to vote at, such meeting, or to receive payment of such dividend, or to receive such allotment rights, or to exercise such rights, as the case may be, notwithstanding any transfer of any stock on the books of the Corporation after such record date fixed as aforesaid.

SECTION 5. DIVIDENDS: The directors may declare dividends from the surplus or net profits arising from the business of the Corporation as and when they deem expedient. Before declaring any dividend there may be reserved out of the accumulated profits such sum or sums as the directors from time to time in their discretion think proper for working capital or as a reserve fund to meeting contingencies or for equalizing dividends or for such other purposes as the directors shall think conducive to the interests of the Company. The directors may close the transfer books for not exceeding twenty (20) days next preceding the day appointed for the payment of any dividend.

ARTICLE VII

MISCELLANEOUS PROVISIONS

SECTION 1. CORPORATE SEAL: The corporate seal shall be circular in form and shall contain the name of the Corporation, and the word "Seal." Said seal may be used by causing it or a facsimile thereof to be impressed or affixed or reproduced or otherwise.

SECTION 2. FISCAL YEAR: The fiscal year of the Company shall be the calendar year.

SECTION 3. PRINCIPAL OFFICE: The principal office of this Corporation may be located outside the State of Arkansas. There shall be kept at such office a book containing the names alphabetically arranged of stockholders of the Corporation and their addresses and the number of shares held by them respectively.

SECTION 4. CHECKS, DRAFTS, NOTES: All checks, drafts or other orders for the payment of money, notes, or other evidences of indebtedness issued in the name of the Corporation shall be signed by the President or such other officer or officers, agent or agents of the Corporation, and in such manner as shall from time to time be determined by resolution of the Board of Directors.

SECTION 5. NOTICE AND WAIVER OF NOTICE: Whenever any notice is required by these By-Laws to be given, personal notice is not meant unless expressly so stated, and any notice so required shall be deemed to be sufficient if given by depositing the same in a post office box in a sealed postpaid wrapper, addressed to the person entitled thereto at his last known post office address, and such notice shall be deemed to have been given on the date of such mailing. Any notice required to be given under these By-Laws may be waived by the person entitled thereto. Stockholders not entitled to vote shall not be entitled to receive notice of any meetings except as otherwise provided by statute.

SECTION 6. INDEMNIFICATION OF DIRECTORS AND OFFICERS: Directors and officers of the Company shall be indemnified to the fullest extent now or hereafter permitted by law in connection with any actual or threatened action or proceeding (including civil, criminal, administrative or investigative proceedings) arising out of their service to the Company or to any other organization at the Company's request. Employees and agents of the Company who are not directors or officers thereof may be similarly indemnified in respect of such service to the extent authorized at any time by the Board of Directors. The provisions of this Section shall be applicable to actions or proceedings commenced after the adoption hereof, whether arising from acts or omissions occurring before or after the adoption hereof, and to persons who have ceased to be directors, officers or employees and shall inure to the benefit of their heirs, executors, and administrators. For the purposes of this Section, directors, officers, trustees or employees of an organization shall be deemed to be rendering service thereto at the Company's request if such organization is, directly or indirectly, a wholly owned subsidiary of the Company or is designated by the Board of Directors as an organization service to which shall be deemed to be so rendered.

SECTION 7. ADVANCEMENT OF LITIGATION EXPENSES: Expenses incurred by a director or officer of the Corporation in defending any actual or threatened action, or proceeding (including civil, criminal, administrative or investigative proceedings) arising out of their service to the Company or to any other organization at the Company's request shall be paid by the Company in advance of the final disposition of such action or proceeding upon receipt of an undertaking by, or on behalf of, such person to repay such amount if it shall ultimately be determined that he is not entitled to be indemnified by the Company as authorized by the relevant provisions of the Arkansas Business Corporation Act as it now exists or as it may hereafter be amended. Such expenses of employees and agents of the Company who are not directors or officers may be similarly advanced to the extent authorized at any time by the Board of Directors. The provisions of this section shall be applicable to actions or proceedings commenced after the adoption hereof, whether arising from acts occurring before or after the adoption hereof, and to persons who have ceased to be directors, officers, and employees and shall inure to the benefit of their heirs, executors, and administrators. For the purposes of this section, directors, officers, trustees, or employees of an organization shall be deemed to be rendering service thereto at the Company's request if such organization is, directly or indirectly, a wholly owned subsidiary of the Company or is designated by the Board of Directors as an organization service to which shall be deemed to be so rendered.

ARTICLE VIII

AMENDMENTS

SECTION 1. AMENDMENT OF BY-LAWS: The stockholders, by the affirmative vote of the holders of a majority of the stock issued and outstanding, or the directors, by the affirmative vote of a majority of the directors, may at any meeting, provided the substance of the proposed amendment shall have been stated in the notice of the meeting, amend or alter any of these By-Laws.

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CONSULTING AGREEMENT

THIS CONSULTING AGREEMENT ("Agreement") is made and entered into as of May 15, 2002, at Fayetteville, Washington County, Arkansas, by and between SOUTHWESTERN ENERGY COMPANY, an Arkansas business corporation, designated herein as SWEN, and CHARLES E. SCHARLAU, designated herein as Scharlau.

W I T N E S S E T H :

A. PARTIES :

1. SOUTHWESTERN ENERGY COMPANY ("SWEN") is an Arkansas business corporation with its principal office being situated in Houston, Harris County, Texas, and it is the parent company of the following wholly-owned subsidiary corporations ("Subsidiaries"):

(a) Arkansas Western Gas Company. Arkansas Western Gas Company ("AWG") is an Arkansas business corporation with its home office being situated in Fayetteville, Washington County, Arkansas, and it is a natural gas distribution public utility in the State of Arkansas;

(b) SEECO, Inc. SEECO, Inc. ("SEECO") is an Arkansas business corporation with its home office situated in Fayetteville, Washington County, Arkansas, and it is engaged in the natural gas exploration, development and production business in the State of Arkansas;

(c) Southwestern Energy Production Company. Southwestern Energy Production Company ("SEPCO") is an Arkansas business corporation with its home office situated in Houston, Harris County, Texas, and it is engaged in the oil and gas exploration, development and production business in the States of Arkansas, Oklahoma, Texas, Louisiana and other areas in the United States and in the Gulf of Mexico; and

(d) AW Realty Company. AW Realty Company ("AWR") is an Arkansas business corporation with its home office situated in Fayetteville, Washington County, Arkansas, and it is engaged in real estate development and sales and owning and operating rental properties in Arkansas.

2. Charles E. Scharlau. Charles E. Scharlau ("Scharlau") is a natural person, he is now and since June of 1951, he has been a licensed attorney at law in the State of Arkansas; and he first became an employee of AWG in 1951, and he served the organization as the head of the legal department until 1968, when he became the President and the Chief Executive Officer of the organization. In addition, he is now and at all times since 1968 he has been a member of and the Chairman of the Board of Directors.

B. RECITALS.

1. SWEN, as the parent corporation of all the Subsidiaries, is engaged in the business of oil and gas exploration and development; the sale and distribution of oil and gas; the natural gas public utility business; the real estate development business; and the ownership of real estate for sale and rental, all for the production of income.

2. Scharlau is a regularly licensed attorney in the State of Arkansas, and is an experienced corporate executive in the field of oil and gas exploration and development, the sale and distribution of oil and gas, the natural gas utility distribution business, the development and sale of real property and the ownership and operation of rental real estate.

3. SWEN wishes to be assured of the consulting services of Scharlau, particularly with reference to the operation of the businesses now conducted by SWEN and the Subsidiaries as specified above and in the areas indicated.

4. The purposes of this Agreement are:

- (a) To provide for the engagement of Scharlau as a business consultant and advisor to SWEN and its Subsidiaries;
- (b) To secure for SWEN and all of its Subsidiaries the advisory and consulting services of Scharlau (the "Services") and to provide for the payment of compensation to Scharlau for the Services to be rendered directly to SWEN and the Subsidiaries and any other entities that are now owned or which may be owned by SWEN and/or the Subsidiaries in the future; and
- (c) To assure that Scharlau shall not compete with SWEN and/or any of its Subsidiaries in any undertaking of any advisory and consulting services in the area of the operations of SWEN and the Subsidiaries during the term hereof and for two (2) years after the expiration of this Agreement.

C. AGREEMENT. FOR AND IN CONSIDERATION of the foregoing recitals and of the mutual and interdependent promises contained herein, SWEN hereby engages Scharlau as an independent consultant and Scharlau accepts such engagement, in accordance with the terms set forth herein:

1. Term. This Agreement shall commence with SWEN's Annual Meeting in 2002 and, subject to the other provisions hereof, shall continue in full force and effect until SWEN's Annual Meeting in 2005 (the "Term"). This Agreement may be extended beyond the initial Term by the mutual agreement of SWEN and Scharlau. Any such extension of the initial Term shall be executed no later than thirty (30) days prior to the expiration of the initial Term. During the Term of this Agreement, Scharlau shall perform such Services to SWEN and represent SWEN in such manner as may be reasonably requested by the Chief Executive Officer or the Board of Directors of SWEN.

2. Compensation. As compensation for the Services, SWEN shall pay to Scharlau the sum of \$5,000 per year (the "Consulting Fee"). The Consulting Fee for the first year of the Term shall be paid to Scharlau no later than June 1, 2002. The Consulting Fee for the second year of the Term shall be paid on the date of SWEN's Annual Meeting in 2003 and the Consulting Fee for the third year of the Term shall be paid on the date of SWEN's Annual Meeting in 2004.

3. Expenses. Scharlau shall be entitled to receive prompt reimbursement for all reasonable expenses incurred by Scharlau in connection with the provision of Services hereunder. Reimbursement shall be made in accordance with the Company's policies and procedures for reimbursing third party consultants.

4. Meetings, Conventions and Seminars. Scharlau is encouraged and is expected to attend seminars, professional meetings and conventions, and educational courses. The cost of travel, tuition or registration, food and lodging for attending those activities will be paid by SWEN. Other costs are Scharlau's expense, unless SWEN authorizes those costs. If those other costs are authorized expenses, Scharlau will be reimbursed after satisfying SWEN's policies and procedures for such reimbursement (which may include a requirement that Scharlau submit an itemized expense voucher).

5. Promotional Expenses. Scharlau is encouraged and is expected, from time to time, to incur reasonable expenses for promoting SWEN's business. Such promotional expenses include travel, entertainment, professional advancement and community service expenses. Scharlau agrees to bear those expenses except to the extent that those expenses are incurred at SWEN's specific direction or those expenses are specifically authorized by SWEN as expenses that SWEN may pay directly or indirectly through reimbursement to Scharlau.

6. Outside Activities. During the Term of this Agreement, Scharlau may (i) serve on corporate, civic or charitable boards or committees; (ii) deliver lectures, fulfill speaking engagements or teach at educational institutions; (iii) manage personal investments and (iv) engage as an attorney, consultant, advisor or investor in any business enterprise, provided that (i) there is no conflict of interest with SWEN as outlined in Section 7 below and (ii) such activities do not significantly interfere with the performance of Scharlau's Services to SWEN. To the extent that any such activities have been conducted by Scharlau before the execution date of this Agreement, such prior conduct of activities and any subsequent conduct of activities similar in nature and scope may not be deemed to interfere with the performance of Scharlau's Services to SWEN.

7. Non-Compete Agreement. For a period of two (2) years from and after the date of the termination of this Agreement, Scharlau agrees that he will not, without the prior consent of SWEN and the Subsidiaries, either directly or indirectly, (i) be engaged as chief operating officer, manager, employee or director of, or agent, consultant or business advisor for, or (ii) own a substantial ownership interest in, any incorporated or

unincorporated oil and gas exploration, production and sales entity in the geographical area of SWEN's and the Subsidiaries' area of operation. SWEN agrees that it will not unreasonably withhold its consent to Scharlau acting as attorney, advisor or consultant to any such entity if there is no conflict of interest with SWEN.

8. Non-Assignability . Neither this Agreement nor any rights hereunder shall be assignable by either party.

9. Inurement . Except as provided in Section 8 above, this Agreement shall be binding upon and inure to the benefit of the parties hereto, their executors, administrators heirs-at-law, successors and assigns.

10. Independent Contractor . The parties agree that the Services to be rendered by Scharlau are as an independent contractor and not as an employee, partner or agent of SWEN or its Subsidiaries.

11. Complete Agreement . This Agreement contains all the agreements, conditions and understandings between the parties with respect to the subject matter hereof and supersedes all prior understandings and agreements (whether oral or written). No amendments to this Agreement shall be effective or binding on any party unless the same shall be in writing and signed by all parties.

12. Applicable Law . This Agreement shall be governed by and construed in accordance with the laws of the State of Arkansas, excluding any choice of law rules which may direct the application of the laws of another jurisdiction. In the event that any portion of the Services provided to SWEN by Scharlau constitute "Lobbying" under Arkansas law, Scharlau shall comply with all rules and regulations that are applicable to "Lobbyists" under Arkansas law.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in original triplicates on the date first hereinabove written.

SOUTHWESTERN ENERGY COMPANY;
ARKANSAS WESTERN GAS COMPANY;
SEECO, INC.; SOUTHWESTERN ENERGY
PRODUCTION COMPANY; AND AW REALTY
COMPANY

By: Compensation Committee of the
Board of Directors

ATTEST:

/s/ Mark K. Boling
Mark K. Boling, Secretary

/s/ Robert L. Howard
Robert L. Howard
/s/ Kenneth R. Mourton
Kenneth R. Mourton
/s/ John Paul Hammerschmidt
John Paul Hammerschmidt

EMPLOYEE:
/s/ Charles E. Scharlau Charles E. Scharlau

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SOUTHWESTERN ENERGY COMPANY

2002 EMPLOYEE STOCK INCENTIVE PLAN (As Adopted October 23, 2002)

1. Purpose of the Plan

The purpose of the Southwestern Energy Company 2002 Employee Stock Incentive Plan is to enable the Company to attract and retain employees that (i) are not officers or directors of Southwestern Energy Company for purposes of Section 16 of the Exchange Act and (ii) are the best available personnel for positions of substantial responsibility, to reward such employees for superior performance and to strengthen the mutuality of interests between such employees and Southwestern's shareholders. The Plan is designed to meet this intent by providing such employees with a proprietary interest in pursuing the long-term growth, profitability and financial success of the Company in order to provide them with additional motivation to continue in the Company's employ and to further its profitable growth.

2. Definitions

As used in the Plan, the following definitions apply to the terms indicated below:

- (a) "Board of Directors" shall mean the Board of Directors of Southwestern.
- (b) "Cause" when used in connection with the termination of a Participant's employment with the Company, shall mean the termination of the Participant's employment by the Company on account of (i) the willful and continued failure by the Participant to substantially perform his duties and obligations (other than any such failure resulting from his incapacity due to physical or mental illness), after a written demand for substantial performance has been delivered to the Participant by the Company or by the Participant's supervisor, which demand identifies in reasonable detail the manner in which the Participant is believed to have not substantially performed his or her duties, (ii) the Participant's willful and serious misconduct which has resulted in or could reasonably be expected to result in material injury to the business, financial condition or reputation of the Company, (iii) the Participant's conviction of, or entering of a plea of *nolo contendere* to, a crime that constitutes a felony or serious misdemeanor or (iv) the breach by the Participant of any written covenant or agreement with the Company not to disclose any information pertaining to the Company or not to compete or interfere with the Company.
- (c) "Change in Control" shall mean the occurrence of any of the following:
- (i) any "person" (as such term is used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), an "Acquiring Person") becomes the "beneficial owner" (as such term is defined in Rule 13d-3 promulgated under the Exchange Act), directly or indirectly, of

securities of Southwestern representing 20% or more of the combined voting power of Southwestern's then outstanding securities, provided, however, that any acquisition by (A)the Company, or any employee benefit plan (or related trust) sponsored or maintained by the Company, or (B)any corporation with respect to which, immediately following such acquisition, more than 60% of, respectively, the then outstanding shares of common stock of such corporation and the combined voting power of the then outstanding voting securities of such corporation entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly, in the aggregate by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the outstanding Southwestern Common Stock and Southwestern voting securities immediately prior to such acquisition in substantially

the same proportion as their ownership, immediately prior to such acquisition, of the outstanding Southwestern Common Stock and Southwestern voting securities, as the case may be, shall not constitute a Change in Control;

(ii) consummation by Southwestern of a reorganization, merger or consolidation (a "Business Combination"), in each case, with respect to which all or substantially all of the individuals and entities who were the respective beneficial owners of the outstanding Southwestern Common Stock and Southwestern voting securities immediately prior to such Business Combination do not in the aggregate, immediately following such Business Combination, beneficially own, directly or indirectly, more than 60% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination in substantially the same proportion as their ownership immediately prior to such Business Combination of the outstanding Southwestern Common Stock and Southwestern voting securities, as the case may be;

(iii) any individual who is nominated by the Board for election to the Board on any date fails to be so elected as a direct or indirect result of any proxy fight or contested election for positions on the Board;

(iv) a "change in control" of Southwestern of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Exchange Act occurs;

(v) (A) a complete liquidation or dissolution of Southwestern or (B) a sale or other disposition of all or substantially all of the assets of both the Exploration Production and the Utility business segments of Southwestern other than to a corporation with respect to which, immediately following such sale or disposition, more than 80% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly, in the aggregate by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the outstanding Southwestern Common Stock and Southwestern voting securities immediately prior to such sale or disposition in substantially the same proportion as their ownership of the outstanding Southwestern Common Stock and Southwestern voting securities, as the case may be, immediately prior to such sale or disposition;

(vi) other than with respect to a person who is employed in the Utility business segment of Southwestern, the sale or other disposition of all or substantially all the assets of the exploration and production business segment of Southwestern, other than to a corporation with respect to which, immediately following such sale or disposition, more than 80% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly, in the aggregate by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the outstanding Southwestern Common Stock and Southwestern voting securities immediately prior to such sale or disposition in substantially the same proportion as their ownership of the outstanding Southwestern Common Stock and Southwestern voting securities, as the case may be, immediately prior to such sale or disposition; or

(vii) a majority of the Board of Directors determines in its sole and absolute discretion that there has been a Change in Control of Southwestern or that there will be a Change in Control of Southwestern upon the occurrence of certain specified events and such events occur.

- (d) "Code" shall mean the Internal Revenue Code of 1986, as amended from time to time.
- (e) "Committee" shall mean the Compensation Committee of the Board of Directors or such other committee as the Board of Directors shall appoint from time to time to administer the Plan and to otherwise exercise and perform the authority and functions assigned to the Committee under the terms of the Plan.
- (f) "Common Stock" shall mean Southwestern's Common Stock, \$.10 par value per share, or any other security into which the Common Stock shall be changed pursuant to the adjustment provisions of Section 10 of the Plan.
- (g) "Company" shall mean collectively Southwestern and each of its Subsidiaries, or individually, Southwestern or one of its Subsidiaries as the context requires.
- (h) "Disability" shall mean a condition entitling a Participant to benefits under the long-term disability policy maintained by the Company and applicable to him or her.
- (i) "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.
- (j) "Fair Market Value" shall mean, with respect to a share of Common Stock, as of the applicable date of determination (i) the closing sales price on the immediately preceding business day of a share of Common Stock as reported on the principal securities exchange on which shares of Common Stock are then listed or admitted to trading or (ii) if not so reported, the average of the closing bid and ask prices for a share of Common Stock on the immediately preceding business day (x) as reported on the National Association of Securities Dealers Automated Quotation System or (y) if not so reported, as furnished by any member of the National Association of Securities Dealers, Inc. selected by the Committee. In the event that the price of a share of Common Stock shall not be so reported, the Fair Market Value of a share of Common Stock shall be determined by the Committee in its absolute discretion.
- (k) "Incentive Award" shall mean an Option, SAR, share of Phantom Stock or a share of Restricted Stock granted to a Participant pursuant to the terms of the Plan.
- (l) "Issue Date" shall mean the date established by the Committee on which certificates representing shares of Restricted Stock shall be issued by Southwestern pursuant to the terms of Section 9(a) hereof.
- (m) "Option" shall mean an Option to purchase shares of Common Stock granted to a Participant pursuant to the terms of the Plan, which Option is subject to the terms and conditions in any agreement evidencing such Option. All Options shall be non-qualified stock options; i.e. Options that do not meet the requirements of Section 422 of the Code.
- (n) "Participant" shall mean an employee of the Company who is not a director or officer of Southwestern for purposes of Section 16 of the Exchange Act, is a full-time employee of the Company, is an "exempt employee" as defined under the Fair Labor Standards Act of 1938, and is granted one or more Incentive Awards pursuant to the Plan and, following the death of any such employee, his or her successors, heirs, executors and administrators, as the case may be.
- (o) "Person" shall mean a "person," as such term is used in Section 13(d) and 14(d) of the Exchange Act.

- (p) “Phantom Stock” shall mean the right granted to a Participant to receive a payment in cash equal to the Fair Market Value of a share of Common Stock, which right is granted pursuant to Section 8 hereof and subject to the terms and conditions contained therein and in any agreement evidencing such share of Phantom Stock.
- (q) “Plan” shall mean this Southwestern Energy Company 2002 Employee Stock Incentive Plan, as it may be amended from time to time.
- (r) “Restricted Stock” shall mean a share of Common Stock which is granted to a Participant pursuant to Section 9 hereof and which is subject to the restrictions set forth in Section 9(c) hereof for so long as such restrictions continue to apply to such share, and such other terms and conditions contained in any agreement evidencing such Restricted Stock.
- (s) “Retirement” shall mean the termination of the employment of a Participant with the Company on or after (i) the first date on which the Participant has both attained age 55 and completed 5 years of service with the Company or (ii) the date on which the Participant attains age 65.
- (t) “SAR” shall mean a stock appreciation right granted to a Participant pursuant to Section 7 hereof which is not related to any Option, which SAR is subject to the terms and conditions contained in any agreement evidencing such SAR.
- (u) “Securities Act” shall mean the Securities Act of 1933, as amended.
- (v) “Southwestern” shall mean Southwestern Energy Company, an Arkansas corporation, and any successor thereto.
- (w) “Subsidiary” shall mean any “subsidiary corporation” within the meaning of Section 425(f) of the Code.
- (x) “Vesting Date” shall mean the date established by the Committee on which a share of Restricted Stock or Phantom Stock may vest.

3. Stock Subject to the Plan

Under the Plan, the Committee may grant to Participants (i) Options, (ii) SARs, (iii) shares of Phantom Stock and/or (iv) shares of Restricted Stock.

Subject to adjustment as provided in Section 10 hereof and the following provisions of this Section 3, the maximum number of shares of Common Stock that may be covered by Incentive Awards granted under the Plan shall be 300,000 shares.

The number of shares of Common Stock to which an Incentive Award relates shall be counted against the number of shares of Common Stock reserved and available under the Plan at the time of grant of the Incentive Award, unless such number of shares of Common Stock cannot be determined at that time, in which case the number of shares of Common Stock actually distributed pursuant to the Incentive Award shall be counted against the number of shares of Common Stock reserved and available under the Plan at the time of distribution; provided, however, that Incentive Awards related to or retroactively added to, or granted in tandem with, substituted for or converted into, other Incentive Awards shall be counted or not counted against the number of shares of Common Stock reserved and available under the Plan in accordance with procedures adopted by the Committee so as to ensure appropriate counting, but avoid double counting; and, provided further, that the number of shares of Common Stock deemed to be

issued under the Plan upon exercise of an Option or another stock-based award in the nature of a stock purchase right shall be reduced by the number of shares of Common Stock surrendered by the Participant in payment of the exercise or purchase price of the Incentive Award.

If any shares of Common Stock to which an Incentive Award relates are forfeited, or payment is made to the Participant in the form of cash, cash equivalents or other property other than shares of Common Stock, or the Incentive Award otherwise terminates without payment being made to the Participant in the form of shares of Common Stock, any shares of Common Stock counted against the number of shares of Common Stock reserved and available under the Plan with respect to such Incentive Award shall, to the extent of any such forfeiture, alternative payment or termination, again be available for Incentive Awards under the Plan.

Shares of Common Stock issued under the Plan may be either newly issued shares or treasury shares, at the discretion of the Committee.

4. Administration of the Plan

The Plan shall be administered by the Committee. The Committee shall, consistent with the terms of the Plan, from time to time designate the employees of the Company who shall be granted Incentive Awards under the Plan and the amount, type and other terms and conditions of such Incentive Awards. All of the powers and responsibilities of the Committee under the Plan may be delegated by the Committee, in writing, to any subcommittee thereof. In addition, the Committee may authorize an executive officer of the Corporation to grant Incentive Awards of a specified type, covering a specified aggregate number of shares of Common Stock and, in the case of any such grant of Options or SARs, at a specified exercise or base price (which may not be less than Fair Market Value on the date of grant) to a specified group of employees and within a specified period of time.

The Committee shall have full, discretionary authority to administer the Plan, including discretionary authority to interpret and construe any and all provisions of the Plan and the terms of any Incentive Award (and any agreement evidencing any Incentive Award) granted thereunder and to adopt and amend from time to time such rules and regulations for the administration of the Plan as the Committee may deem necessary or appropriate. Decisions of the Committee shall be final, binding and conclusive on all parties.

At or after the date of grant of an Incentive Award under the Plan, the Committee may (i) accelerate the date on which any such Incentive Award becomes vested, exercisable or transferable, as the case may be, (ii) extend the term of any such Incentive Award, including, without limitation, extending the period following a termination of a Participant's employment during which any such Incentive Award may remain outstanding, or (iii) waive any conditions to the vesting, exercisability or transferability, as the case may be, of any such Incentive Award.

Whether an authorized leave of absence, or absence in military or government service, shall constitute termination of employment shall be determined by the Committee.

No member of the Committee shall be liable for any action, omission, or determination relating to the Plan, and Southwestern shall indemnify and hold harmless each member of the Committee and each other director or employee of the Company to whom any duty or power relating to the administration or interpretation of the Plan has been delegated against any cost or expense (including counsel fees) or liability (including any sum paid in settlement of a claim with the approval of the Committee) arising out of any action, omission or determination relating to the Plan, unless, in either case, such action, omission

or determination was taken or made by such member, director or employee in bad faith and without reasonable belief that it was in the best interests of the Company.

5. *Eligibility*

The employees who shall be eligible to receive Incentive Awards pursuant to the Plan shall be those employees of the Company who are not officers or directors of Southwestern for the purposes of Section 16 of the Exchange Act, who are full-time employees of the Company and who are "exempt employees" as defined under the Fair Labor Standards Act of 1938 that the Committee shall select from time to time. All Incentive Awards granted under the Plan shall be evidenced by a separate written agreement entered into by the Company and the recipient of such Award.

6. *Options*

The Committee may from time to time grant Options pursuant to the Plan to Participants, which Options shall be evidenced by agreements in such form as the Committee shall from time to time approve. Options shall comply with and be subject to the following terms and conditions:

(a) Identification of Options

All Options granted under the Plan shall be identified in the agreement evidencing such Options as non-qualified stock options.

(b) Exercise Price

The exercise price per share of Common Stock covered by any Option granted under the Plan shall be not less than 100% of the Fair Market Value of a share of Common Stock on the date on which such Option is granted.

(c) Term and Exercise of Options

(1) Each Option shall become vested and exercisable on such date or dates, during such period and for such number of shares of Common Stock as shall be determined by the Committee on or after the date such Option is granted; provided, however, that no Option shall be exercisable after the expiration of ten years from the date such Option is granted; and, provided, further, that each Option shall be subject to earlier termination, expiration or cancellation as provided in the Plan or in the agreement evidencing such Option.

(2) Each Option may be exercised in whole or in part, to the extent such Option is vested on the date of exercise; provided, that no partial exercise of an Option shall be for an aggregate exercise price of less than \$1,000. The partial exercise of an Option shall not cause the expiration, termination or cancellation of the remaining portion thereof.

(3) An Option shall be exercised by delivering written notice to Southwestern's principal office, to the attention of its Secretary, no less than three business days in advance of the effective date of the proposed exercise. Such notice shall specify the number of shares of Common Stock with respect to which the Option is being exercised and the effective date of the proposed exercise and shall be signed by the Participant. The Participant may withdraw such notice at any time prior to the close of business on the business day immediately preceding the effective date of the proposed exercise. Payment for shares of Common Stock purchased upon the exercise of an Option shall be made on the effective date of such exercise either (i) in cash, by certified check, bank cashier's check or wire transfer,

(ii) through a directed brokerage service, if any is made available to Participants by Southwestern or (iii) subject to the approval of the Committee, in shares of Common Stock that have been owned by the Participant for at least six months prior to the effective date of exercise and valued at their Fair Market Value on the effective date of such exercise, or partly in shares of Common Stock with the balance in cash, by certified check, bank cashier's check or wire transfer. Any payment in shares of Common Stock shall be effected by the delivery of such shares to the Secretary of Southwestern, duly endorsed in blank or accompanied by stock powers duly executed in blank, together with any other documents and evidences as the Secretary of Southwestern shall require from time to time.

(4) Certificates for shares of Common Stock purchased upon the exercise of an Option shall be issued in the name of the Participant and delivered to the Participant as soon as practicable following the effective date on which the Option is exercised.

(5) During the lifetime of a Participant, each Option granted to him shall be exercisable only by him. No Option shall be assignable or transferable otherwise than by will or by the laws of descent and distribution. Notwithstanding the foregoing, with the prior consent of the Committee, an Option, including the right to exercise such Option, may be transferred by a Participant during the Participant's lifetime, but only to: (i) one or more of a Participant's spouse or natural or adopted lineal descendants; or (ii) a trust, partnership, or corporation or other similar entity which is owned solely by one or more of the Participant's spouse or natural or adopted lineal descendants or which will hold such Options solely for the benefit of one or more of such persons.

(Effect of Termination of Employment

d)

(1) Unless the Committee provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate for any reason other than Disability, Retirement, Cause or death (i) Options granted to such Participant, to the extent that they were vested and exercisable at the time of such termination, shall remain exercisable until the expiration of ninety days after such termination, on which date they shall expire to the extent not exercised, and (ii) Options granted to such Participant, to the extent that they were not vested and exercisable at the time of such termination, shall expire at the close of business on the date of such termination; provided, however, that no Option shall be exercisable after the expiration of its original term.

(2) Unless the Committee provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate on account of the Disability or Retirement of the Participant, (i) such Participant shall be entitled to exercise, at any time or from time to time after such termination and until the first anniversary of such termination, Options granted to him or her hereunder to the extent that such Options were vested and exercisable at the time of such termination, provided however, that no Option shall be exercisable after the expiration of its original term, and (ii) Options granted to such Participant, to the extent that they were not vested and exercisable at the time of such termination, shall expire at the close of business on the date of such termination. Options that are not exercised prior to the first anniversary of such termination shall expire on such anniversary date.

(3) Unless the Committee provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate on account of the death of the Participant, (i) such Participant's estate or beneficiary under his or her will shall be entitled to exercise, at any time or from time to time until the first anniversary of such termination, Options granted to him or her hereunder to the extent that such Options were vested and exercisable at the time of such termination; provided, however, that no Option shall be exercisable after the expiration of its original term, and (ii) Options granted to such Participant, to the extent that they were not vested and exercisable

at the time of such termination, shall expire at the close of business on the date of such termination. Options that are not exercised prior to the first anniversary of such termination shall expire on such anniversary date.

(4) In the event of the termination of a Participant's employment for Cause, all outstanding Options granted to such Participant, whether or not then vested or exercisable, shall expire at the commencement of business on the date of such termination; provided, however, that no Participant shall be deemed to have been terminated for Cause during the two year period following any Change in Control.

(5) For purposes of this Section 6(d), an Option shall be deemed to be vested and exercisable on the date of the termination of the employment of a Participant with the Company to the extent, if any, it becomes vested and exercisable by acceleration by the Committee.

(e Effect of Change in Control
)

Upon the occurrence of a Change in Control, each Option granted under the Plan and outstanding at such time shall become fully and immediately vested and exercisable and shall remain exercisable until its expiration, termination or cancellation pursuant to the terms of the Plan and the agreement evidencing such Option.

(f Cash Tax Bonuses and Loans
)

(1) The Committee may grant to any Participant a cash tax bonus in an amount determined by the Committee to enable the Participant to pay any federal, state or local income taxes arising out of the exercise of an Option.

(2) The Committee may provide a loan to any Participant in an amount determined by the Committee to enable the Participant to pay (i) any federal, state or local income taxes arising out of the exercise of an Option or (ii) the exercise price with respect to any Option. Any such loan (i) shall be for such term and at such rate of interest as the Committee may determine, (ii) shall be evidenced by a promissory note in a form determined by the Committee and executed by the Participant and (iii) shall be subject to such other terms and conditions as the Committee may determine.

7. Stock Appreciation Rights

The Committee may grant SARs pursuant to the Plan, which SARs shall be evidenced by an agreement in such form as the Committee shall from time to time approve. SARs shall comply with and be subject to the following terms and conditions:

(a) Exercise Price

The base price per share of Common Stock covered by any SAR granted under the Plan shall be not less than 100% of the Fair Market Value of a share of Common Stock on the date on which such SAR is granted.

(b) Benefit Upon Exercise
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The exercise of an SAR with respect to any number of shares of Common Stock prior to the occurrence of a Change in Control shall entitle the Participant to (i) a cash payment, for each such

share, equal to the excess of (A)the Fair Market Value of a share of Common Stock on the effective date of such exercise over (B)the per share base price of the SAR, (ii)the issuance or transfer to the Participant of the greatest number of whole shares of Common Stock which on the date of the exercise of the SAR have an aggregate Fair Market Value equal to such excess or (iii)a combination of cash and shares of Common Stock in amounts equal to such excess, all as determined by the Committee. The exercise of an SAR with respect to any number of shares of Common Stock upon or after the occurrence of a Change in Control shall entitle the Participant to a cash payment, for each such share, equal to the excess of (i)the greater of (A)the highest price per share of Common Stock paid in connection with such Change in Control and (B)the Fair Market Value of a share of Common Stock on the effective date of exercise over (ii)the per share base price of the SAR. Such payment, transfer or issuance shall occur as soon as practical, but in no event later than five business days, after the effective date of the exercise.

(c Term and Exercise of SARs
)

(1)Each SAR shall be exercisable on such date or dates, during such period and for such number of shares of Common Stock as shall be determined by the Committee and set forth in the SAR agreement with respect to such SAR; provided, however, that no SAR shall be exercisable after the expiration of ten years from the date such SAR is granted; and, provided, further, that each SAR shall be subject to earlier termination, expiration or cancellation as provided in the Plan or in the agreement evidencing such SAR.

(2)Each SAR may, to the extent vested and exercisable, be exercised in whole or in part; provided, that no partial exercise of an SAR shall be for an aggregate base price of less than \$1,000. The partial exercise of an SAR shall not cause the expiration, termination or cancellation of the remaining portion thereof.

(3)An SAR shall be exercised by delivering written notice to Southwestern's principal office, to the attention of its Secretary, no less than three business days in advance of the effective date of the proposed exercise. Such notice shall specify the number of shares of Common Stock with respect to which the SAR is being exercised and the effective date of the proposed exercise and shall be signed by the Participant. The Participant may withdraw such notice at any time prior to the close of business on the business day immediately preceding the effective date of the proposed exercise.

(4)During the lifetime of a Participant, each SAR granted to him or her shall be exercisable only by the Participant. No SAR shall be assignable or transferable otherwise than by will or by the laws of descent and distribution.

(Effect of Termination of Employment
d)

(1)Unless the Committee provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate for any reason other than Cause, Disability, Retirement or death (i) SARs granted to such Participant, to the extent that they were vested and exercisable at the time of such termination, shall remain exercisable until the expiration of ninety days after such termination, on which date they shall expire to the extent not exercised, and (ii)SARs granted to such Participant, to the extent that they were not vested and exercisable at the time of such termination, shall expire at the close of business on the date of such termination; provided, however, that no SAR shall be vested and exercisable after the expiration of its original term.

(2)Unless the Committee provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate on account of the Disability, Retirement or death of the Participant (i)SARs granted to such Participant, to the extent that they were

vested and exercisable at the time of such termination, shall remain exercisable until the expiration of one year after such termination, on which date they shall expire to the extent not exercised, and (ii) SARs granted to such Participant, to the extent that they were not vested and exercisable at the time of such termination, shall expire at the close of business on the date of such termination; provided, however, that no SAR shall be exercisable after the expiration of its original term.

(3) In the event of the termination of a Participant's employment for Cause, all outstanding SARs granted to such Participant, whether or not then vested or exercisable, shall expire at the commencement of business on the date of such termination; provided, however, that no Participant shall be deemed to have been terminated for Cause during the two year period following any Change in Control.

(e Effect of Change in Control
)

Upon the occurrence of a Change in Control, any SAR granted under the Plan and outstanding at such time shall become fully and immediately vested and exercisable and shall remain exercisable until its expiration, termination or cancellation pursuant to the terms of the Plan.

8. *Phantom Stock*

The Committee may grant shares of Phantom Stock pursuant to the Plan. Each grant of shares of Phantom Stock shall be evidenced by an agreement in such form as the Committee shall from time to time approve. Each grant of shares of Phantom Stock shall comply with and be subject to the following terms and conditions:

(a) Vesting Date

At the time of the grant of shares of Phantom Stock, the Committee shall establish a Vesting Date or Vesting Dates with respect to such shares and the conditions, if any, which must be satisfied on or prior to such Vesting Date for the Participant's rights with respect to such shares of Phantom Stock to become vested. The Committee may divide such shares into classes and assign a different Vesting Date and different conditions for each class. Provided that all conditions to the vesting of a share of Phantom Stock imposed pursuant to Section 8(c) hereof and any agreement evidencing such Phantom Stock are satisfied and except as provided in Section 8(d) hereof, upon the occurrence of the Vesting Date with respect to a share of Phantom Stock, the Participant's rights with respect to such share shall become fully vested and nonforfeitable.

(b Benefit Upon Vesting
)

Upon the vesting of a share of Phantom Stock, a Participant shall be entitled to receive in cash, within 30 days of the applicable Vesting Date or at such later date as the Committee shall determine, an amount in cash in a lump sum equal to the sum of (i) the Fair Market Value of a share of Common Stock on the applicable Vesting Date with respect to such share of Phantom Stock and (ii) the aggregate amount of cash dividends paid with respect to a share of Common Stock during the period commencing on the date on which such share of Phantom Stock was granted to the Participant and terminating on the applicable Vesting Date for such share.

(c Conditions to Vesting
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At the time of the grant of shares of Phantom Stock, the Committee may impose such restrictions or conditions, not inconsistent with the provisions hereof, to the vesting of such shares as it

deems appropriate. By way of example and not by way of limitation, the Committee may require, as a condition to the vesting of any class or classes of shares of Phantom Stock, that the Participant and/or the Company achieve such performance criteria as the Committee may specify at the time of the grant of such shares of Phantom Stock and/or that the Participant continue in the employment of the Company for a specified period of time.

(Effect of Termination of Employment
d)

(1)Unless the Committee provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate for any reason other than Cause prior to the Vesting Date of shares of Phantom Stock granted to such Participant, a portion of such shares, to the extent not forfeited or cancelled on or prior to such termination pursuant to any provision hereof or of the agreement evidencing such Phantom Stock, shall vest on the date of such termination. The portion referred to in the preceding sentence shall be determined by the Committee at or after the time of the grant of such shares of Phantom Stock and may be based on the achievement of any conditions imposed by the Committee with respect to such shares pursuant to Section8(c). Such portion may be zero.

(2)In the event of the termination of a Participant's employment for Cause, all shares of Phantom Stock granted to such Participant which have not vested as of the date of such termination shall immediately be forfeited and cancelled.

(e Effect of Change in Control
)

Upon the occurrence of a Change in Control, all shares of Phantom Stock which have not theretofore vested, or been cancelled or forfeited pursuant to any provision hereof or of the agreement evidencing such Phantom Stock, shall immediately vest and become nonforfeitable.

9. *Restricted Stock*

The Committee may grant shares of Restricted Stock pursuant to the Plan. Each grant of shares of Restricted Stock shall be evidenced by an agreement in such form as the Committee shall from time to time approve. Each grant of shares of Restricted Stock shall comply with and be subject to the following terms and conditions:

(a Issue Date and Vesting Date
)

At the time of the grant of shares of Restricted Stock, the Committee shall establish an Issue Date or Issue Dates and a Vesting Date or Vesting Dates with respect to such shares and the conditions, if any, which must be satisfied on or prior to such Vesting Date for the Participant's rights with respect to such shares of Restricted Stock to become vested. The Committee may divide such shares into classes and assign a different Issue Date and/or Vesting Date and different conditions for each class. Upon the occurrence of the Issue Date with respect to a share of Restricted Stock, a share of Restricted Stock shall be issued in accordance with the provisions of Section 9(d) hereof. Provided that all conditions to the vesting of a share of Restricted Stock imposed pursuant to Section9(b) hereof and any agreement evidencing such Restricted Stock are satisfied, and except as provided in Section9(c) and 9(f) hereof, upon the occurrence of the Vesting Date with respect to a share of Restricted Stock, the Participant's rights with respect to such share shall become fully vested and the restrictions of Section9(c) hereof shall cease to apply to such share.

(b Conditions to Vesting
)

At the time of the grant of shares of Restricted Stock, the Committee may impose such restrictions or conditions, not inconsistent with the provisions hereof, to the vesting of such shares as it deems appropriate. By way of example and not by way of limitation, the Committee may require, as a condition to the vesting of any class or classes of shares of Restricted Stock, that the Participant and/or the Company achieve such performance criteria as the Committee may specify at the time of the grant of such shares and/or that the Participant continue in the employment of the Company for a specified period of time.

(Restrictions on Transfer Prior to Vesting
c
)

Prior to the vesting of a share of Restricted Stock, such share of Restricted Stock shall not be transferable under any circumstances and no transfer of a Participant's rights with respect to such share, whether voluntary or involuntary, by operation of law or otherwise, shall vest the transferee with any interest or right in or with respect to such share, but immediately upon any attempt to transfer such rights, such share, and all of the rights related thereto, shall be cancelled and shall be forfeited by the Participant and the transfer shall be of no force or effect.

(d Issuance of Certificates
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(1) Reasonably promptly after the Issue Date with respect to shares of Restricted Stock, the Company shall cause to be issued stock certificates, registered in the name of the Participant to whom such shares were granted, evidencing such shares; provided, that the Company shall not cause to be issued such a stock certificate unless it has received a stock power duly endorsed in blank with respect to such shares. Each such stock certificate shall bear the following legend:

The transferability of this certificate and the shares of stock represented hereby are subject to the restrictions, terms and conditions (including forfeiture provisions and restrictions against transfer) contained in the Southwestern Energy Company 2002 Employee Stock Incentive Plan and an Agreement entered into between the registered owner of such shares and Southwestern Energy Company. A copy of the Plan and Agreement is on file in the office of the Secretary of Southwestern Energy Company, 2350 N. Sam Houston Parkway East, Suite 300, Houston, Texas 77032.

Such legend shall not be removed from the certificate evidencing such shares unless and until such shares become vested and the restrictions on the transfer thereof lapse pursuant to the terms hereof and any agreement evidencing such Restricted Stock.

(2) Each certificate issued pursuant to Section 9(d)(1) hereof, together with the stock powers relating to the shares of Restricted Stock evidenced by such certificate, shall be deposited by the Company with a custodian designated by the Company until the applicable shares become vested. The Company shall cause such custodian to issue to the Participant a receipt evidencing the certificates held by it which are registered in the name of the Participant.

(e Consequences Upon Vesting
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Upon the vesting of a share of Restricted Stock pursuant to the terms hereof, the restrictions of Section 9(c) hereof shall cease to apply to such share. Reasonably promptly after a share of Restricted Stock vests pursuant to the terms hereof, the Company shall cause to be issued and

delivered to

the Participant to whom such shares were granted, a certificate evidencing such share, free of the legend set forth in Section 9(d)(1) hereof, together with any other property of the Participant held by the custodian pursuant to Section 9(d)(2) hereof.

(f Effect of Termination of Employment
)

(1) Unless the Committee provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate for any reason other than Cause prior to the vesting of shares of Restricted Stock granted to such Participant, a portion of such shares, to the extent not forfeited or cancelled on or prior to such termination pursuant to any provision hereof or any agreement evidencing such Restricted Stock, shall vest on the date of such termination. The portion referred to in the preceding sentence shall be determined by the Committee and may be based on the achievement of any conditions imposed by the Committee with respect to such shares pursuant to Section 9(b). Such portion may be zero.

(2) In the event of the termination of a Participant's employment for Cause, all shares of Restricted Stock granted to such Participant which have not vested as of the date of such termination shall immediately be cancelled and forfeited.

(g Effect of Change in Control
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Upon the occurrence of a Change in Control, all shares of Restricted Stock which have not theretofore vested (including those with respect to which the Issue Date has not yet occurred), or been cancelled or forfeited pursuant to any provision hereof or any agreement evidencing such Restricted Stock, shall immediately vest and all restrictions applicable thereto shall lapse.

(h Cash Tax Bonuses and Loans
)

(1) The Committee may grant to any Participant a cash tax bonus in an amount determined by the Committee to enable the Participant to pay any federal, state or local income taxes arising out of the award or vesting of Restricted Stock.

(2) The Committee may provide a loan to any Participant in an amount determined by the Committee to enable the Participant to pay any federal, state or local income taxes arising out of the award or vesting of Restricted Stock. Any such loan (i) shall be for such term and at such rate of interest as the Committee may determine, (ii) shall be evidenced by a promissory note in a form determined by the Committee and executed by the Participant and (iii) shall be subject to such other terms and conditions as the Committee may determine.

10. *Adjustment Upon Changes in Common Stock*

(a Adjustment upon Certain Events
)

In the event of any change in the shares of Common Stock outstanding by reason of any stock dividend or split, recapitalization, reorganization, merger, consolidation, combination, spin-off, reclassification or exchange of shares or similar corporate change (such change, an "Adjustment Event"), (i) the maximum aggregate number of shares of Common Stock with respect to which Incentive Awards may be granted under the Plan, (ii) the type or class of securities with respect to which Incentive Awards may be granted under the Plan, (iii) the number, type and class of securities covered by any then outstanding Options and SARs and the respective exercise and base prices applicable under any then outstanding Options and SARs and (iv) the number, type and class of securities covered by any then

outstanding shares of Phantom Stock or Restricted Stock and the respective limitations or other criteria applicable to any then outstanding shares of Phantom Stock or Restricted Stock may be appropriately adjusted by the Committee as it shall determine is appropriate to prevent enlargement or dilution of the rights of Participants hereunder. In the event of any change in the shares of Common Stock outstanding by reason of any other event or transaction, the Committee may, but need not, make such adjustments in the number, type and class of shares of securities with respect to which Incentive Awards may be granted or that are subject to then outstanding Incentive Awards, and the other terms and conditions of then outstanding Incentive Awards, as the Committee may deem appropriate to prevent enlargement or dilution of the rights of Participants hereunder.

(b Outstanding Restricted Stock
)

Unless the Committee otherwise determines, any securities or other property (including dividends paid in cash) issued or paid with respect to shares of Restricted Stock that are outstanding as of the date an Adjustment Event occurs which have not become vested as of such date shall be promptly deposited with the custodian designated pursuant to Paragraph9(d)(2) hereof and shall not become vested or transferable to the Participant unless and until such Participant's rights with respect to the related shares of Restricted Stock become vested.

(Outstanding Options and SARs – Certain Transactions
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Notwithstanding any other provision of the Plan, in the event of (i)a dissolution or liquidation of Southwestern, (ii)a sale of all or substantially all of Southwestern's assets or (iii)a merger, consolidation, or similar business transaction involving Southwestern, the Committee shall have the power to:

(A)cancel, effective immediately prior to the occurrence of such event, all or a portion of the Options and SARs outstanding immediately prior to such event (whether or not then vested or exercisable), and, in full consideration for such cancellation, pay to the Participant to whom such Option or SAR was granted an amount in cash, for each share of Common Stock subject to each such cancelled Option or SAR, respectively, immediately prior to such event, equal to the excess of (A)the value, as determined by the Committee (as constituted immediately prior to such event) of the property (including cash) received by the holder of a share of Common Stock as a result of such event over (B)the exercise or base price of such Option or SAR; or

(B)provide for the exchange of all or a portion of such Options and/or SARs outstanding immediately prior to such event (whether or not then vested or exercisable) for equivalent options or stock appreciation rights covering securities of the acquiring entity (or the ultimate parent thereof) and, incident thereto, make an equitable adjustment as determined by the Committee (as constituted immediately prior to such event) in the exercise or base price of such exchanged option or stock appreciation right, and/or the number, type and class of securities subject to such exchanged option or stock appreciation right or, if appropriate, provide for a cash payment to the Participant to whom such Option or SAR was granted in partial consideration for the exchange of the Option or SAR.

(d) No Other Rights

Except as expressly provided in the Plan, no Participant shall have any rights by reason of any subdivision or consolidation of shares of stock of any class, the payment of any dividend, any increase or decrease in the number of shares of stock of any class or any dissolution, liquidation, merger or consolidation of Southwestern or any other corporation. Except as expressly provided in the Plan, no issuance by Southwestern of shares of stock of any class, or securities convertible into shares of stock of

any class, shall affect, and no adjustment by reasons thereof shall be made with respect to, the number of shares of Common Stock subject to an Incentive Award or the exercise or base price of any Option or SAR.

11. *Rights as a Stockholder*

No person shall have any rights as a stockholder with respect to any shares of Common Stock covered by or relating to any Incentive Award granted pursuant to this Plan until the date of the issuance of a stock certificate with respect to such shares. Except as otherwise expressly provided in Section 8, 9 or 10 hereof, no adjustment of any Incentive Award shall be made for dividends or other rights for which the record date occurs prior to the date such stock certificate is issued.

12. *No Special Employment Rights; No Right to Incentive Award*

Nothing contained in the Plan or any Incentive Award shall confer upon any Participant any right with respect to the continuation of his or her employment by the Company or interfere in any way with the right of the Company at any time to terminate such employment or to increase or decrease the compensation of the Participant from the rate in existence at the time of the grant of an Incentive Award.

No person shall have any claim or right to receive an Incentive Award hereunder. The Committee's granting of an Incentive Award to a Participant at any time shall neither require the Committee to grant an Incentive Award to such Participant or any other Participant or other person at any time nor preclude the Committee from making subsequent grants to such Participant or any other Participant or other person.

13. *Securities Matters*

(a) Southwestern shall be under no obligation to effect the registration pursuant to the Securities Act of any shares of Common Stock to be issued hereunder or to effect similar compliance under any state laws. Notwithstanding anything herein to the contrary, Southwestern shall not be obligated to cause to be issued or delivered any certificates evidencing shares of Common Stock pursuant to the Plan unless and until Southwestern is advised by its counsel that the issuance and delivery of such certificates is in compliance with all applicable laws, regulations of governmental authority and the requirements of any securities exchange on which shares of Common Stock are traded. The Committee may require, as a condition to the issuance and delivery of certificates evidencing shares of Common Stock pursuant to the terms hereof, that the recipient of such shares make such covenants, agreements and representations, and that such certificates bear such legends, as the Committee deems necessary or desirable.

(b) The exercise of any Option granted hereunder shall only be effective at such time as counsel to Southwestern shall have determined that the issuance and delivery of shares of Common Stock pursuant to such exercise is in compliance with all applicable laws, regulations of governmental authority and the requirements of any securities exchange on which shares of Common Stock are traded. Southwestern may, in its sole discretion, defer the effectiveness of an exercise of an Option hereunder or the issuance or transfer of shares of Common Stock pursuant to any Incentive Award pending or to ensure compliance under federal or state securities laws. Southwestern shall inform the Participant in writing of its decision to defer the effectiveness of the exercise of an Option or the issuance or transfer of shares of Common Stock pursuant to any Incentive Award. During the period that the effectiveness of the exercise of an Option has been deferred, the Participant may, by written notice, withdraw such exercise and obtain the refund of any amount paid with respect thereto.

14. *Withholding Taxes*

(a) Cash Remittance

Whenever shares of Common Stock are to be issued upon the exercise of an Option or SAR or the grant of Restricted Stock or restrictions on shares of Restricted Stock are to lapse, Southwestern shall have the right to require the Participant to remit to Southwestern in cash an amount sufficient to satisfy federal, state and local withholding tax requirements, if any, attributable to such exercise, grant or lapse prior to the delivery of any certificate or certificates for such shares or the effectiveness of the lapse of such restrictions. In addition, upon the exercise of an SAR or receipt of, or payment in respect of, a share of Phantom Stock, Southwestern shall have the right to withhold from any cash payment required to be made pursuant thereto an amount sufficient to satisfy the federal, state and local withholding tax requirements, if any, attributable to such exercise, receipt or payment.

(b) Stock Remittance

At the election of the Participant, subject to the approval of the Committee, when shares of Common Stock are to be issued upon the exercise of an Option or SAR or the grant of Restricted Stock, or when restrictions on Restricted Stock lapse, the Participant may tender to Southwestern a number of shares of Common Stock that have been owned by the Participant for at least six months having a Fair Market Value at the tender date determined by the Committee to be sufficient to satisfy the federal, state and local withholding tax requirements, if any, attributable to such exercise or grant but not greater than such withholding obligations. Such election shall satisfy the Participant's obligations under Section 14(a) hereof, if any.

(c) Stock Withholding

At the election of the Participant, subject to the approval of the Committee, when shares of Common Stock are to be issued upon the exercise of an Option or SAR or the grant of Restricted Stock, or when restrictions on Restricted Stock lapse, Southwestern shall withhold a number of such shares having a Fair Market Value at the exercise date determined by the Committee to be sufficient to satisfy the federal, state and local withholding tax requirements, if any, attributable to such exercise, grant or lapse of restrictions, but not greater than such withholding obligations. Such election shall satisfy the Participant's obligations under Section 14(a) hereof, if any.

15. *Amendment or Termination of the Plan*

The Board of Directors may at any time suspend or discontinue the Plan or revise or amend it in any respect whatsoever; provided, however, that any revision or amendment to the Plan that requires the approval of shareholders pursuant to New York Stock Exchange Listing Requirements or applicable law shall not be made until such approval of shareholders is obtained. Nothing herein shall restrict the Committee's ability to exercise its discretionary authority hereunder pursuant to Section 4 hereof, which discretion may be exercised without amendment to the Plan. No action hereunder may, without the consent of a Participant, materially reduce the Participant's rights under any previously granted and outstanding Incentive Award. Nothing herein shall limit the right of Southwestern to pay compensation of any kind outside the terms of the Plan.

16. *No Obligation to Exercise*

The grant to a Participant of an Option or SAR shall impose no obligation upon such Participant to exercise such Option or SAR.

17. Transfers Upon Death

Subject to Section6(c)(5), upon the death of a Participant, outstanding Incentive Awards granted to such Participant may be exercised only by the executors or administrators of the Participant's estate or by any person or persons who shall have acquired such right to exercise by will or by the laws of descent and distribution. Subject to Section6(c)(5), no transfer by will or the laws of descent and distribution of any Incentive Award, or the right to exercise any Incentive Award, shall be effective to bind Southwestern unless the Committee shall have been furnished with (a)written notice thereof and with a copy of the will and/or such evidence as the Committee may deem necessary to establish the validity of the transfer and (b)an agreement by the transferee to comply with all the terms and conditions of the Incentive Award that are or would have been applicable to the Participant and to be bound by the acknowledgements made by the Participant in connection with the grant of the Incentive Award. Except as provided in Section17 or Section6(c)(5), no Incentive Award shall be transferable, and shall be exercisable only by a Participant during the Participant's lifetime.

18. Expenses and Receipts

The expenses of the Plan shall be paid by Southwestern. Any proceeds received by Southwestern in connection with any Incentive Award will be used for general corporate purposes.

19. Failure to Comply

In addition to the remedies of Southwestern elsewhere provided for herein, failure by a Participant to comply with any of the terms and conditions of the Plan or the agreement executed by such Participant evidencing an Incentive Award, unless such failure is remedied by such Participant within ten days after having been notified of such failure by the Committee, shall be grounds for the cancellation and forfeiture of such Incentive Award, in whole or in part, as the Committee may determine.

20. Effective Date and Term of Plan

The Plan was adopted by the Board of Directors on October23, 2002. No grants may be made under the Plan after October23, 2004.

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SOUTHWESTERN ENERGY COMPANY 2002 PERFORMANCE UNIT PLAN

1. Purpose of the Plan

This Southwestern Energy Company 2002 Performance Unit Plan is intended to promote the interests of the Company and its shareholders by providing the employees of the Company who are largely responsible for the management, growth and protection of the business of the Company, with incentives and rewards for their contribution to the increase in the value of the Company and to encourage them to continue in the service of the Company.

2. Definitions

Whenever used herein, the masculine pronoun shall be deemed to include the feminine, the singular to include the plural, unless the context clearly indicates otherwise, and the following capitalized words and phrases are used herein with the meaning thereafter ascribed:

("Account" shall mean a bookkeeping account on the Company's books established pursuant to Section5(b) of this Plan. The Account ashall initially reflect the number of Performance Units granted to a Participant pursuant to Section5(a) of this Plan.

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("Board of Directors" shall mean the Board of Directors of Southwestern.

b

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(“Cause”, when used in connection with the termination of a Participant’s employment with the Company, shall mean the termination of the Participant’s employment by the Company on account of:

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- (i the willful and continued failure by the Participant to substantially perform his duties and obligations (other than any such failure resulting from his incapacity due to physical or mental illness), after a written demand for substantial performance has been delivered to the Participant by the Company or by the Participant’s supervisor, which demand identifies in reasonable detail the manner in which the Participant is believed to have not substantially performed his or her duties;
- (i the Participant’s willful and serious misconduct which has resulted in or could reasonably be expected to result in material injury to
- i) the business, financial condition or reputation of the Company;
- (i the Participant’s conviction of, or entering of a plea of nolo contendere to, a crime that constitutes a felony or serious misdemeanor; or
- ii)

(the breach by the Participant of any written covenant or agreement with the Company not to disclose any information pertaining to the
i Company or not to compete or interfere with the Company.

v
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(“Change in Control” shall mean the occurrence of any of the following:

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(any “person” (as such term is used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 (the “Exchange Act”), an
i “Acquiring Person”) becomes the “beneficial owner” (as such term is defined in Rule13d-3 promulgated under the Exchange Act),
) directly or indirectly, of securities of Southwestern representing 20% or more of the combined voting power of Southwestern’s then
outstanding securities, provided, however, that any acquisition by:

(Southwestern or any of its subsidiaries, or any employee benefit plan (or related trust) sponsored or maintained by Southwestern or any
Aof its subsidiaries; or

)

(any corporation with respect to which, immediately following such acquisition, more than 60% of, respectively, the then outstanding
Bshares of Common Stock of such corporation and the combined voting power of the then outstanding voting securities of such
) corporation entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly, in the aggregate by all
or substantially all of the individuals and entities who were the beneficial owners, respectively, of the outstanding Southwestern Common
Stock and Southwestern voting securities immediately prior to such acquisition in substantially the same proportion as their ownership,
immediately prior to such acquisition, of the outstanding Southwestern Common Stock and Southwestern voting securities, as the case
may be, shall not constitute a Change in Control;

(consummation by Southwestern of a reorganization, merger or consolidation (a “Business Combination”), in each case, with respect to
i which all or substantially all of the individuals and entities who were their respective beneficial owners of the outstanding Southwestern
i Common Stock and Southwestern voting securities immediately prior to such Business Combination do not in the aggregate,
) immediately following such Business Combination, beneficially own, directly or indirectly, more than 60% of, respectively, the then
outstanding shares of Common Stock and the combined voting power of the then outstanding voting securities entitled to vote generally
in the election of directors, as the case may be, of the corporation resulting from such Business Combination in substantially the same
proportion as their ownership immediately prior to such Business Combination of the outstanding Southwestern Common Stock and
Southwestern voting securities, as the case may be;

- (i) any individual who is nominated by the Board of Directors for election to the Board of Directors on any date fails to be so elected as a
- ii) direct or indirect result of any proxy fight or contested election for positions on the Board of Directors;
- (i) a “change in control” of Southwestern of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of
- v) Regulation 14A promulgated under the Exchange Act occurs;

((A a complete liquidation or dissolution of Southwestern, or

v)

)

- (B a sale or other disposition of all or substantially all of the assets of both the Exploration and Production and the Utility business
-) segments of Southwestern other than to a corporation with respect to which, immediately following such sale or disposition, more than 80% of, respectively, the then outstanding shares of Common Stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly, in the aggregate by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the outstanding Southwestern Common Stock and Southwestern voting securities immediately prior to such sale or disposition in substantially the same proportion as their ownership of the outstanding Southwestern Common Stock and Southwestern voting securities, as the case may be, immediately prior to such sale or disposition;

- (v other than with respect to a person who is employed in the Utility business segment of Southwestern, the sale or other disposition of
- i) all or substantially all the assets of the Exploration and Production business segment other than to a corporation with respect to which, immediately following such sale or disposition, more than 80% of, respectively, the then outstanding shares of Common Stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly, in the aggregate by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the outstanding Southwestern Common Stock and Southwestern voting securities immediately prior to such sale or disposition in substantially the same proportion as their ownership of the outstanding Southwestern Common Stock and Southwestern voting securities, as the case may be, immediately prior to such sale or disposition; or

- (v a majority of the Board of Directors determines in its sole and absolute discretion that there has been a Change in Control of
- ii) Southwestern or that

there will be a Change in Control of Southwestern upon the occurrence of certain specified events and such events occur.

(“Commencement Date” shall mean, with respect to a particular grant of Performance Units hereunder, the first day of the Plan Year immediately following the date of grant of such Performance Units.

)

(“Company” shall mean Southwestern and each of its Subsidiaries.

f

)

(“Disability” shall mean a condition entitling a Participant to benefits under the long-term disability policy maintained by the Company and applicable to him.

)

(“Grant Agreement” shall mean a written document issued to a Participant that shall specify the grant of Performance Units to the Participant, the applicable Performance Measures set by the Plan Administrator and conditions to which the grant is subject.

)

(“Participant” shall mean an employee of the Company who is eligible to participate in the Plan and to whom one or more Performance Units have been granted pursuant to the Plan and, following the death of any such employee, his or her successors, heirs, executors and administrators, as the case may be.

(“Payment Value” shall mean, as of the end of each Performance Period, the value, expressed in dollars, of each Performance Unit issued under the Plan. The Payment Value will be determined by multiplying the target value by the percentage or percentages assigned to the level of the Company’s actual financial performance, based on the Performance Measures and based on associated percentages assigned to the various levels of performance of the Performance Measures at the beginning of the Performance Period. If the attainment of a Performance Measure occurs between the stated levels, the Payment Value will be determined by linear extrapolation.

(“Performance Measures” shall mean the possible standards for measuring the Payment Value of the Performance Units, as determined by the Plan Administrator on the date of grant and as more particularly set forth in the Grant Agreement.

)

Relative performance will be measured against goals or against peers, as determined by the Plan Administrator on the date of grant.

(“Performance Period” shall mean the time period over which the Performance Measures will be analyzed for purposes of determining the Payment Value of the Performance Units granted to a Participant. Unless otherwise specified by the Plan Administrator, the

) Performance Period shall be thirty-six months from the Commencement Date.

(“Performance Unit” shall mean a unit of interest under the Plan the value of which depends upon the financial performance of the Company in comparison to the Performance Measures specified for the applicable Performance Period.
)

(“Plan” shall mean this Southwestern Energy Company 2002 Performance Unit Plan, as it may be amended from time to time.
n
)

(“Plan Administrator” shall mean the individual or individuals as the Board of Directors shall appoint from time to time to administer the Plan and to otherwise exercise and perform the authority and functions assigned to the Plan Administrator under the terms of the Plan, as set forth in Section 3 of this Plan.

(“Plan Year” shall mean Southwestern’s fiscal year.
p
)

(“Southwestern” shall mean Southwestern Energy Company, an Arkansas corporation, and any successor thereto.
q
)

(“Subsidiary” shall mean any “subsidiary corporation” within the meaning of Section 425(f) of the Internal Revenue Code of 1986, as amended from time to time.
)

(“Vesting Date” shall mean the date established by the Plan Administrator on which a Performance Unit may vest and becomes non-forfeitable except as set forth in Section 5 of this Plan.
)

3. Administration of the Plan

The Plan shall be administered by a committee of the Board of Directors consisting of two or more persons, at least two of whom qualify as a “non-employee director,” within the meaning of Rule 16b-3 promulgated under Section 16 of the Exchange Act, and an “outside director,” within the meaning of Treasury Regulation Section 1.162-27(e)(2). The Plan Administrator shall, consistent with the terms of the Plan, from time to time designate the employees of the Company who shall be granted Performance Units under the Plan. All of the powers and responsibilities of the Plan Administrator under the Plan may be delegated by the Plan Administrator, in writing, to any subplan administrator thereof. In addition, the Plan Administrator may authorize an executive officer of Southwestern to grant Performance Units to a specified group of employees and within a specified period of time.

The Plan Administrator shall have full, discretionary authority to administer the Plan, including discretionary authority to interpret and construe any and all provisions of the Plan and the terms of any Performance Unit (and any agreement evidencing any Performance Unit) granted thereunder and to adopt and amend from time to time such rules and regulations for the administration of the Plan as the Plan Administrator may deem necessary or appropriate. Decisions of the Plan Administrator shall be final, binding and conclusive on all parties.

At or after the date of grant of a Performance Unit under the Plan, the Plan Administrator may

(accelerate the date on which any such Performance Unit becomes vested or paid,

a
)

(extend the term of any such Performance Unit, including, without limitation, extending the period following a termination of a Participant's employment during which any Performance Unit may remain outstanding, or

)

(waive any conditions to vesting of any such Performance Unit.

c
)

Whether an authorized leave of absence, or absence in military or government service, shall constitute termination of employment shall be determined by the Plan Administrator.

No member of the Plan Administrator shall be liable for any action, omission or determination relating to the Plan, and Southwestern shall indemnify and hold harmless each member of the Plan Administrator and each other director or employee of the Company to whom any duty or power relating to the administration or interpretation of the Plan has been delegated against any cost or expense (including counsel fees) or liability (including any sum paid in settlement of a claim with the approval of the Plan Administrator) arising out of any action, omission or determination relating to the Plan, unless, in either case, such action, omission or determination was taken or made by such member, director or employee in bad faith and without reasonable belief that it was in the best interests of the Company.

4. Eligibility

The employees who shall be eligible to receive Performance Units pursuant to the Plan shall be those employees of the Company that the Plan Administrator shall select from time to time, including those key employees (including officers of Southwestern, whether or not they are directors of Southwestern) who are largely responsible for the management, growth and protection of the business of the Company. All Performance Units granted under the Plan shall be evidenced by a separate Grant Agreement entered into by the Company and the recipient of such award.

5. Performance Units

The Plan Administrator may grant Performance Units pursuant to the Plan. Each grant of a Performance Unit shall be evidenced by a Grant Agreement in such form as the Plan Administrator shall from time to time approve. Each grant of a Performance Unit shall comply with and be subject to the following terms and conditions:

(Grants

a
)

For each Performance Period, the Plan Administrator shall determine whether to grant any Performance Units and, if Performance Units are granted, the Plan Administrator shall notify those Participants who are to receive grants, which shall be evidenced by a Grant Agreement between Southwestern and the Participant. The number of Performance Units to be granted to a Participant shall be determined by the Plan Administrator based on the Participant's role and

responsibilities and competitive levels of long-term compensation. No fractional Performance Units shall be granted. For each Performance Period, the Plan Administrator shall determine the Performance Measures for the Performance Period, determine the weighting of the Performance Measures for the Performance Period and specify such approvals in the Grant Agreement.

(Interests of a Participant

b
)

The Company shall create individual Accounts on its books to reflect the number of Performance Units credited to each Participant for a Performance Period. No Participant or any other person shall under any circumstances acquire any property interest in any specific assets of the Company, and the Plan shall be unfunded. Nothing contained in this Plan and no action taken pursuant hereto shall create or be construed to create a fiduciary relationship between the Company, the Plan Administrator or the Board of Directors and any Participant or any other person. To the extent that any person acquires a right to receive payment from the Company hereunder, such right shall be no greater than the right of any unsecured general creditor of the Company.

(Vesting

c
)

Except as provided in Section 5(f) or as specified in the Grant Agreement, each Participant's right to the Performance Units awarded for any Performance Period shall vest one-third per year starting on the day of the first anniversary of the date of grant, provided that the Participant has not terminated employment.

(Effect of Termination of Employment

d
)

(Unless the Plan Administrator provides otherwise on or after the date of grant, in the event that the employment of a Participant with the Company shall terminate for any reason other than Cause all unvested Performance Units granted to such Participant shall expire at the commencement of business on the date of such termination, and no payment shall be made to the Participant with respect thereto. Except as otherwise provided herein or in the Grant Agreement, Southwestern shall make payment respecting vested Performance Units upon expiration of the original Performance Period under the original terms for such vested Performance Units.

(In the event of the termination of a Participant's employment for Cause, all outstanding Performance Units granted to such Participant shall expire at the commencement of business on the date of such termination, and no payment shall be made to the Participant with respect thereto.

)

(e Performance Unit Benefit

)

The Performance Units will have a Payment Value at the end of the applicable Performance Period contingent upon the attainment of the Performance Measures, as specified in the Participant's Grant Agreement, as determined by the Plan Administrator.

The Plan Administrator shall use Southwestern's year end audited financial statements in determining the extent to which the Performance Measures were achieved during the relevant Performance Period. The Plan Administrator shall certify in writing whether and the extent to which the Performance Measure for each Performance Period has been met within 120 days following the issuance of such financial statements (the "Certification Period").

The amount of the Payment Value due a Participant shall be made in cash.

Except as otherwise provided herein or in the Grant Agreement, Southwestern shall pay the Participant the total amount of Payment Value due the Participant at the conclusion of a Performance Period on such date following the conclusion of such Performance Period as the Plan Administrator shall designate, but in no event later than the end of the Certification Period.

The Plan Administrator may permit a Participant to defer the receipt of some or all of the payment due under this Section and have any such sum credited to a deferred compensation plan maintained by the Company, provided that such election is made before Payment Value is calculated and due, as specified by the applicable deferred compensation plan.

(Effect of Change in Control

f

)

Upon the occurrence of a Change in Control, each Performance Unit granted under the Plan and outstanding at such time shall become fully and immediately vested. In full satisfaction of amounts due under the Performance Units, Southwestern shall pay the Participant the target value (as specified in the Grant Agreement) or, if greater and the Plan Administrator, in its sole discretion, elects, an amount that the Plan Administrator determined to be the projected amount that would have been payable had the Performance Period run its cycle. Such amounts shall be paid within five (5) business days after the Change in Control.

6. No Special Employment Rights; No Right to Performance Unit

Nothing contained in the Plan or any Performance Unit shall confer upon any Participant any right with respect to the continuation of his employment by the Company or interfere in any way with the right of the Company at any time to terminate such employment or to increase or decrease the compensation of the Participant from the rate in existence at the time of the grant of a Performance Unit.

No person shall have any claim or right to receive a Performance Unit hereunder. The Plan Administrator's granting of a Performance Unit to a Participant at any time shall neither require the Plan Administrator to grant a Performance Unit to such Participant or any other Participant or other person at any time nor preclude the Plan Administrator from making subsequent grants to such Participant or any other Participant or other person.

7. Withholding Taxes

Upon the payment to the Participant of the Payment Value of the Performance Unit or any deferral of such payment, Southwestern shall have the right to withhold from any such payment required to be made pursuant thereto or such deferral an amount sufficient to satisfy the Federal, state and/or local withholding tax requirements, if any, attributable to such payment.

8. Amendment or Termination of the Plan

The Board of Directors or Plan Administrator may at any time suspend or discontinue the Plan or revise or amend it in any respect whatsoever.

Nothing herein shall restrict the Plan Administrator's ability to exercise its discretionary authority hereunder pursuant to Section 3 hereof, which discretion may be exercised without amendment to the Plan. However, no action hereunder may, without the consent of a Participant, reduce the Participant's rights under any previously granted and outstanding Performance Units. Nothing herein shall limit the right of the Company to pay compensation of any kind outside the terms of the Plan.

9. Transferability of Performance Unit

During the lifetime of a Participant, each Performance Unit to the Participant shall be exercisable by such Participant. No Performance Unit shall be assignable or transferable otherwise than by will or by the laws of descent and distribution.

10. Failure to Comply

In addition to the remedies of Southwestern elsewhere provided for herein, failure by a Participant to comply with any of the terms and conditions of the Plan or the agreement executed by such Participant evidencing a Performance Unit, unless such failure is remedied by such Participant within ten days after having been notified of such failure by the Plan Administrator, shall be grounds for the cancellation and forfeiture of such Performance Unit, in whole or in part, as the Plan Administrator may determine.

11. Adjustment.

Upon the occurrence of any event which could reasonably be expected to have an impact on the stock or Performance Measures of the Company or its peer companies, the Plan Administrator shall have the right, but not the obligation, in its sole discretion, to make such adjustments to the calculations of the payments to be made hereunder as it deems appropriate to reflect such events,

provided that no such adjustments shall reduce the Participant's rights under any previously granted and outstanding Performance Units.

12. No Effect on Benefit Plans.

No amounts payable hereunder shall count in computing any benefits payable under any other benefit plans maintained by the Company except to extent such plans otherwise incorporate such payments by express reference to the Plan.

13. Governing Law

The interpretation, performance and enforcement of this Plan shall be governed by the laws of the State of Arkansas, to the extent not preempted by Federal law.

14. Effective Date and Term of Plan

The Plan was adopted by the Board of Directors on December 11, 2002 and effective as of December 11, 2002. No grants may be made under the Plan after December 31, 2005.

10

Oklahoma Properties

PURCHASE AND SALE AGREEMENT

BY AND BETWEEN

SOUTHWESTERN ENERGY PRODUCTION COMPANY

AS SELLER

AND

DUTCH PETROLEUM, LLC

AS BUYER

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PURCHASE AND SALE AGREEMENT

THIS PURCHASE AND SALE AGREEMENT (this "Agreement") is dated November 5, 2002, by and between SOUTHWESTERN ENERGY PRODUCTION COMPANY, an Arkansas corporation, with an office at 2350 N. Sam Houston Parkway East, Suite 300, Houston, Texas 77032 (hereinafter referred to as "Seller") and DUTCH PETROLEUM, LLC, an Oklahoma limited liability company, with an office at 2110 Bank One Center, 100 North Broadway, Oklahoma City, Oklahoma 73102 (hereinafter referred to as "Buyer"), and is based on the following premises:

WHEREAS, Seller desires to sell, assign and convey to Buyer and Buyer desires to purchase and accept certain oil and gas properties and related interests; and

WHEREAS, the parties have reached agreement regarding such sale and purchase.

NOW, THEREFORE, for valuable consideration and the mutual covenants and agreements herein contained, Seller and Buyer agree as follows:

ARTICLE 1. DEFINITIONS

1. Definitions: In this Agreement, capitalized terms have the meanings provided in this Article 1, unless expressly provided otherwise in other Articles. All defined terms include both the singular and the plural. All references to Articles or Sections refer to Articles or Sections in this Agreement, and all references to Exhibits and Schedules refer to the Exhibits and Schedules attached to this Agreement. The Exhibits and Schedules which are attached hereto are incorporated in and made a part of this Agreement.

"Accounting Referee" has the meaning set forth in Section 6.8.

"Affiliate" means and includes any entity that, directly or indirectly, through one or more intermediaries, controls or is controlled by or is under common control with the entity specified.

"Alleged Title Defect" means a Title Defect (as hereinafter defined) which is asserted by Buyer in accordance with Section 4.2.

"Assignment and Bill of Sale" means a document in the form of Exhibit B.

"Assumed Contracts" means all operating agreements, unit agreements, unit operating agreements, exploration agreements, farmout agreements, farm-in agreements, Hydrocarbon sales, purchase, gathering, transportation, treating, marketing, exchange, processing and fractionating agreements, surface leases, and other contracts and agreements respecting the

Properties that are either of record in the counties/parishes where the Properties are located or are reflected or referenced in Seller's files.

"Business Day" means a Day (as hereinafter defined) excluding Saturdays, Sundays and U.S. legal holidays.

"Casualty Loss" means any loss, damage or reduction in value resulting from mechanical failure or defects, catastrophic occurrences, acts of God and any other losses which are not the result of normal wear and tear or of natural reservoir changes.

"Certificate" means a document in the form of Exhibit C.

"Claim" means any and all claims, demands, suits, causes of action, investigations, administrative proceedings, or other legal proceedings, losses, damages, liabilities, judgments, assessments, settlements, fines, notices of violation, penalties, interest, obligations and costs (including attorneys' fees and costs of litigation) of any kind or character (whether or not asserted prior to the date hereof, and whether known or unknown, fixed or unfixed, conditional or unconditional, based on negligence, strict liability or otherwise, choate or inchoate, liquidated or unliquidated, secured or unsecured, accrued, absolute, contingent or otherwise) which are brought by or owed to a Third Party (as hereinafter defined).

"Close" or "Closing" means the consummation of the transfer of title to the Properties to Buyer, including execution and delivery of all documents provided herein.

"Closing Date" means November 15, 2002, or such other date as may be mutually agreed upon by the parties on which Closing occurs in accordance with the terms of this Agreement; provided, however, Buyer shall have the right, at its option, to extend the date of Closing from November 15, 2002 to November 22, 2002 upon the delivery of written notice thereof to Seller no later than November 11, 2002.

"Day" means a calendar day consisting of twenty-four (24) hours from midnight to midnight.

"Defensible Title" means, as to the Leases, such title held by Seller that, subject to and except for the Permitted Encumbrances (as hereinafter defined):

- (a) Entitles Seller to own and receive payment of revenues for not less than the "Net Revenue Interests" set forth on Exhibit A of all oil, gas and associated liquid and gaseous hydrocarbons produced, saved and marketed from the Leases;
- (b) Obligates Seller to bear costs and expenses relating to the ownership, operation, maintenance and repair of the wells and facilities located on or attributable to

the Leases in an amount not greater than the “Working Interests” set forth on Exhibit A, unless there is a corresponding proportionate increase in the Net Revenue Interests; and

(c) Is free and clear of all liens, encumbrances, burdens and defects against the Leases.

“Earnest Money Deposit” has the meaning set forth in Section 3.2.

“Effective Time” means October 1, 2002, at 7:00 a.m., local time where the Properties are located.

“Environmental Claims” means all Claims for pollution or environmental damages of any kind, including without limitation, those relating to: (a) remediation and/or clean-up thereof, (b) damage to and/or loss of any property or resource, and/or (c) injury or death of any person(s) whomsoever, including without limitation Claims relating to breach of Environmental Laws, common law causes of action such as negligence, gross negligence, strict liability, nuisance or trespass, or fault imposed by statute, rule, regulation or otherwise (but specifically excluding any Claims relating to asbestos or NORM (as hereinafter defined), which are covered by Section 8.4 hereof), and including all costs associated with remediation and clean up, and fines and penalties associated with any of the foregoing.

“Environmental Defect” has the meaning set forth in Section 5.2.2.

“Environmental Inspection Period” has the meaning set forth in Section 5.2.2.

“Environmental Laws” means all laws, statutes, ordinances, permits, orders, judgments, rules or regulations which are promulgated, issued or enacted by a governmental entity having appropriate jurisdiction that, (a) relate to the prevention of pollution or environmental damage, (b) the remediation of pollution or environmental damage, or (c) the protection of the environment generally; including without limitation, the Clean Air Act, as amended, the Clean Water Act, as amended, the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, the Federal Water Pollution Control Act, as amended, the Resource Conservation and Recovery Act of 1976, as amended, the Safe Drinking Water Act, as amended, the Toxic Substance and Control Act, as amended, the Superfund Amendments and Reauthorization Act of 1986, as amended, the Hazardous and the Solid Waste Amendments Act of 1984, as amended, and the Oil Pollution Act of 1990, as amended.

“Final Accounting Settlement” has the meaning set forth in Section 6.6.

“Final Settlement Date” has the meaning set forth in Section 6.6.

“Hydrocarbons” has the meaning given to such term in the definition of Properties.

“Interest Adjustment” has the meaning set forth in Section 4.2.

“Laws” means any and all applicable laws, statutes, ordinances, permits, decrees, orders, judgments, rules or regulations (including, without limitation, Environmental Laws) which are promulgated, issued or enacted by a governmental entity having appropriate jurisdiction.

“Leases” has the meaning given to such term in the definition of Properties.

“Material Contracts” shall mean those Assumed Contracts identified on Exhibit K.

“Non-Foreign Affidavit” means a document in the form of Exhibit D.

“NORM” means naturally occurring radioactive materials.

“Permitted Encumbrances” means:

- (a) Royalties, overriding royalties, production payments, reversionary interests, convertible interests, net profits interests, division orders and similar burdens encumbering the Properties as of the Effective Time to the extent the net cumulative effect of such burdens do not operate to (i) reduce the net revenue interests of the Properties to less than the net revenue interests set forth on Exhibit A or (ii) cause an increase in the working interest in any Property from that shown on Exhibit A without a proportionate increase in the net revenue interest for such Property;
- (b) Preferential purchase rights and consents to assignment and similar contractual provisions encumbering the Properties with respect to which, prior to Closing, (i) waivers or consents are obtained from the appropriate parties, or (ii) the appropriate time period for asserting such rights have expired without an exercise of such rights;
- (c) Preferential purchase rights encumbering the Properties which are exercised by a Third Party, if the affected Properties are withdrawn from this sale transaction and handled in accordance with Section 3.4;
- (d) All rights to consent by, required notices to, filings with, or other actions by governmental entities in connection with the sale or conveyance of the Properties, if the same are customarily obtained subsequent to the transfer of title;
- (e) Rights reserved to or vested in any governmental entity having appropriate jurisdiction to control or regulate the Properties in any manner whatsoever, and all Laws of any such governmental entity;
- (f) Easements, rights-of-way, servitudes, surface leases, sub-surface leases, pipelines, platforms, facilities, utility lines, telephone lines, power lines, and structures

on, over and through the Properties, to the extent such rights, interests or structures do not materially interfere with the operation of the Properties;

(g) Liens for taxes or assessments not yet due or not yet delinquent or, if delinquent, that are being contested by Seller in good faith in the normal course of business;

(h) Liens of operators relating to obligations not yet due or not yet delinquent or, if delinquent, that are being contested by Seller in good faith in the normal course of business;

(i) The Material Contracts;

(j) Title Defects that Buyer has waived under Section 4.3; and

(k) Such encumbrances or burdens on, or defects or irregularities in the title to, the Properties that do not materially interfere with the operation, value or use of the Properties affected thereby and that would be considered not material by a reasonable and prudent person engaged in the business or ownership, development and operation of oil and gas properties when applying general industry standards.

“Properties” means the following properties (real, personal or mixed) and rights (contractual or otherwise):

- (a) All of Seller’s right, title and interest in, to and under or derived from the oil and gas leasehold interests, fee interests, mineral interests and overriding royalty interests described on Exhibit A (collectively, the “Leases”);
- (b) All of Seller’s right, title and interest in and to, or derived from, all of the presently existing and valid unitization and pooling agreements and units (including all units formed by voluntary agreement and those formed under the rules, regulations, orders or other official acts of any governmental entity having appropriate jurisdiction) to the extent they relate to any of the interests which are expressly described on Exhibit A;
- (c) All of Seller’s right, title and interest in and to all oil, gas and/or other liquid or gaseous hydrocarbons (collectively, the “Hydrocarbons”) produced from or attributable to Seller’s interest in the Leases and attributable to the period from and after the Effective Time;
- (d) All of Seller’s right, title and interest in and to, or derived from, all of the presently existing and valid oil sales contracts, casinghead gas sales contracts, gas sales contracts, processing contracts, gathering contracts, transportation contracts, easements, rights-of-way, servitudes, surface leases and other contracts (including the Assumed

Contracts), to the extent the same are assignable and relate to any of the interests which are expressly described on ExhibitA;
(e)All of Seller's right, title and interest in and to all personal property and improvements (collectively, the "Equipment"), including without limitation, wells (whether producing, plugged and abandoned, shut-in, injection, disposal or water supply), tanks, boilers, platforms, buildings, fixtures, machinery, equipment, pipelines, utility lines, power lines, telephone lines, telegraph lines and other appurtenances located on, in, under and about the Leases, to the extent the same are situated upon and used or held for use by Seller solely in connection with the ownership, operation, maintenance and repair of the interests which are expressly described on ExhibitA, subject to the reservations stated below;

(f)All franchises, licenses, permits, approvals, consents, certificates and other authorizations and other rights granted by governmental authorities and all certificates of convenience or necessity, immunities, privileges, grants and other rights that relate to the Properties or the ownership or operation of any thereof, to the extent the same are assignable (the "Permits"); and

(g)All of Seller's "Records" (hereinafter defined).

Seller EXCEPTS, RESERVES AND RETAINS unto itself, its successors and assigns, and specifically excludes from the Properties, those properties (real, personal or mixed) and rights (contractual or otherwise) more particularly described on ExhibitJ attached hereto.

"Purchase Price" has the meaning set forth in Section3.1.

"Records" means all of Seller's books, records and files related to the Properties, including all (i)abstracts, title opinions, title reports, environmental site assessments, environmental compliance reports, lease and land files, surveys, analyses, compilations, correspondence, filings with and reports to regulatory agencies and other documents, contracts, agreements and instruments that in any manner relate to the Properties, (ii)computer databases that are owned by or licensed to Seller that relate to the Properties, (iii)geophysical, geological, engineering, exploration, production and other technical data, magnetic field recordings, digital processing tapes, field prints, summaries, reports and maps, whether written or in electronically reproducible form, that are in the possession of Seller and relate to the Properties and (iv)all other books, records, files and magnetic tapes containing title or other information that are in the possession of Seller and relate to the Properties (the "Data"), but specifically excluding (i)previous offers and economic analyses associated with the acquisition, sale or exchange of the Properties, (ii)interpretive information, (iii)personnel information, (iv)corporate, legal, financial and tax information, (v)information covered by a non-disclosure obligation, (vi) information covered by a legal privilege and (vii)any other Data or information that Seller does not have the right to assign to Buyer.

“Title Defect” means any lien, encumbrance, encroachment or defect associated with Seller’s title to the Properties that would cause Seller not to have Defensible Title.

“Third Party” means any person or entity, governmental or otherwise, other than Seller and Buyer.

ARTICLE 2. SALE AND PURCHASE

On the Closing Date, effective as of the Effective Time, and upon the terms and conditions herein set forth, Seller agrees to sell and assign the Properties to Buyer and Buyer agrees to buy and accept the Properties.

ARTICLE 3. PURCHASE PRICE

3.1 Purchase Price. Subject to adjustments as set forth herein, the total purchase price for the Properties shall be Twenty-Six Million Eight Hundred Fifty Thousand Dollars (US \$26,850,000) (the “Purchase Price”), payable in full at Closing in immediately available funds.

3.2 Earnest Money Deposit. Upon the execution of this Agreement, Buyer shall pay to Seller a deposit in the amount of One Million Five Hundred Thousand Dollars (US \$1,500,000) (the “Earnest Money Deposit”). If Closing occurs, the Purchase Price shall be credited by the amount of the Earnest Money Deposit. If Closing does not occur, the Earnest Money Deposit shall be refunded to Buyer, unless (a) Closing does not occur because of Buyer’s failure or refusal to Close in breach of this Agreement or (b) because the conditions precedent to Seller’s obligation to Close provided in Section 14.1 are unmet at the time set for Closing, in which case Seller shall retain the Earnest Money Deposit as liquidated damages and not as a penalty. If, however, in the case of either (a) or (b) above, any conditions precedent to Buyer’s obligation to Close provided in Section 14.2 are unmet at the time set for Closing, Seller shall not be entitled to retain the Earnest Money Deposit as hereinabove provided. In the event that Closing occurs after November 22, 2002, through the fault of Buyer, interest shall be payable on the Purchase Price from November 22, 2002 through and including the Closing Date at the rate of ten percent (10%) per annum.

3.3 Allocation. Attached hereto as Exhibit F is Buyer’s good faith allocation of the Purchase Price which shall be used in providing any required preferential purchase right notifications and in determining any Purchase Price adjustments pursuant to this Agreement.

3.4 Preferential Rights. If any of the Properties are burdened with preferential purchase rights, the assignment of the Properties subject to such preferential rights shall be conditioned upon Seller obtaining the necessary waiver or expiration of such right, and this Agreement shall not constitute an assignment or attempted assignment thereof without such

waiver or expiration. If, prior to Closing, (i) a holder of a preferential purchase right notifies Seller that it intends to exercise its rights with respect to any of the Properties to which its preferential purchase right applies, or (ii) the time for exercising any preferential purchase right has not expired and the holder thereof has not waived the same prior to the Closing Date, the Properties covered by said preferential purchase right shall be excluded from the Properties to be conveyed to Buyer at Closing, and the Purchase Price shall be reduced by the value allocated to said Properties by Buyer in accordance with Section 3.3. If (i) the holder of the preferential purchase right fails to consummate the purchase of the Properties that are the subject of any notice of an intent to exercise such right received before or after Closing, (ii) the preferential purchase right expires or (iii) notice of a waiver of the preferential purchase right is received by Seller, Seller shall promptly notify Buyer in writing. Within five (5) Business Days after Buyer's receipt of such notice or the Closing Date, whichever is later, Seller shall sell to Buyer, and Buyer shall purchase from Seller, such Properties under the terms of this Agreement for a price equal to the aforesaid value allocated to such Properties. Notwithstanding the foregoing, Buyer shall have no obligation to purchase such Properties if Buyer does not receive such notice within sixty (60) Days following Closing.

3.5 Consents. If any of the Leases require the consent of a Third Party to assign Seller's interest therein, the assignment of such lease(s) subject to consent requirements shall be conditioned upon Seller obtaining such consent prior to Closing (except for consents from governmental bodies customarily obtained after assignment which shall not be required to be obtained prior to Closing). Seller shall use all reasonable efforts to obtain all such consents. With respect to any leasehold interest for which consent is not obtained prior to Closing, such interest shall not be conveyed to Buyer at Closing and the Purchase Price shall be reduced to account for exclusion of the affected Property. If Seller obtains the required consent(s) within sixty (60) days following Closing, Seller shall sell and Buyer shall purchase the interest(s) affected thereby under the terms of this Agreement for a price equal to the Purchase Price adjustment made therefor at Closing. There shall be no obligations of sale or purchase of the affected interest(s) in the Properties following sixty (60) days after the Closing Date.

ARTICLE 4. REVIEW BY BUYER

4.1 Review of Records. Seller shall make available to Buyer after execution of this Agreement Records in Seller's possession relating to the Properties including, without limitation all environmental site assessments and environmental compliance reports in Seller's possession relating to the Properties which are listed on Exhibit L. Buyer shall be entitled to review said Records during normal business hours or other mutually agreeable time and shall have a right to request a reasonable number of copies of such Records, at Buyer's expense.

4.2 Adjustment of Purchase Price for Title Defects. As soon as reasonably practicable after Buyer's review of the Records in accordance with Section 4.1, but in no event later than five (5) Business Days prior to the Closing Date, Buyer shall notify Seller in writing of any Properties which are subject to Alleged Title Defects and/or whose net revenue interest and/or

working interest is/are less than or greater than that amount specified on ExhibitA (collectively, the “Interest Adjustments”). Notice of Title Defects or Interest Adjustments shall include a description and full explanation of each Title Defect and Interest Adjustment being claimed and a value which Buyer in good faith attributes to each. With respect to Alleged Title Defects, Seller may undertake to satisfy some, all or none of those raised by Buyer, at Seller’s sole cost and expense. Buyer and Seller shall meet at least three (3) Business Days prior to the Closing Date in an attempt to mutually agree on a resolution with respect to any Alleged Title Defects or Interest Adjustments which by such time have not been agreed between the parties in writing. It is recognized that good faith differences of opinion may exist between Buyer and Seller in connection with Alleged Title Defects or Interest Adjustments, including without limitation, disputes as to (i)whether or not the alleged defect constitutes a Title Defect within the meaning of this Agreement, (ii) whether or not the magnitude of such defect is great enough that Buyer is contractually entitled to assert such Title Defect, (iii)whether or not the Title Defect was properly and timely asserted by Buyer pursuant to this Article, and (iv)the appropriate upward or downward adjustment, if any, to be made to the Purchase Price on account of such Title Defect. In determining whether a portion of a Property contains a Title Defect, it is the intent of the parties to include, when possible, only that portion of the Property adversely affected. If the value properly allocated to a Title Defect cannot be determined directly from ExhibitF because the Title Defect is included within, but does not totally comprise, the Property to which the allocated value relates, Seller and Buyer shall attempt to proportionately reduce the allocated value on ExhibitF. Closing shall not be delayed, postponed or canceled because a resolution of a Title Defect or Interest Adjustment is not agreed prior to the Closing Date, except to the extent that the Alleged Title Defect being asserted is failure of Seller’s title in whole or in part to any portion(s) of the Properties (a “Material Defect”). To the extent that any portion(s) of the Properties are alleged to be affected by a Material Defect which remains on the scheduled Closing Date uncured or otherwise unresolved by the parties, such affected portion(s) of the Properties shall be excluded from the Properties conveyed to Buyer at Closing and the Purchase Price shall be reduced accordingly. If the parties cannot mutually agree on a Purchase Price adjustment for a Material Defect, Buyer shall have the right to (i)proceed to Closing and accept the Property with the Material Defect with no Purchase Price adjustment or (ii)terminate this Agreement as to the Property affected by the Material Defect and receive a Purchase Price adjustment for such Property as set forth on ExhibitF or, where applicable, the proportionate allocated value. If any difference of opinion regarding an Alleged Title Defect (excluding any Material Defect) or Interest Adjustment or value of the Title Defect (excluding any Material Defect) or Interest Adjustment (collectively, the “Title Defect Dispute”) is not resolved by mutual agreement of Buyer and Seller prior to the Closing Date, then either party has the right, exercisable within sixty (60) days after the Closing Date, to refer the same to arbitration in accordance with Article13, but using one (1)mutually agreeable arbitrator who is an attorney licensed in the state in which the Properties are located and who has at least fifteen (15)years oil and gas title experience in such state. Subject to the terms of Article13, the decision of the arbitrator regarding Title Defect Dispute(s) shall be final as between the parties.

Notwithstanding anything herein to the contrary, in no event shall either party have any obligations hereunder with respect to any Title Defects or Interest Adjustments except to the extent that (i)each such Title Defect or Interest Adjustment exceeds One Thousand Dollars (\$1,000) and (ii)all such Title Defects and Interest Adjustments exceed in the aggregate One Hundred Twenty-Five Thousand Dollars (US \$125,000), and each party hereby waives all upward or downward adjustments to the Purchase Price for Title Defects and/or Interest Adjustments the individual value of which is \$1,000 or less and the cumulative value of which is \$125,000 or less.

4.3 Waiver. Except for claims Buyer asserts under Seller's special warranty of title described in Section9.1, all Alleged Title Defects and Interest Adjustments which are not raised by Buyer within the time period provided in Section4.2 or which are raised and not thereafter submitted to arbitration in accordance with such Section shall be deemed waived by Buyer for all purposes, and Buyer shall have no right to seek an adjustment to the Purchase Price, make a claim against Seller or seek indemnification from Seller on account of the same. All upward Interest Adjustments which are not raised by Seller within the time period provided in Section4.2 or which are raised and not thereafter submitted to arbitration in accordance with such Section shall be deemed waived by Seller for all purposes, and Seller shall have no right to seek an adjustment to the Purchase Price, make a claim against Buyer or seek indemnification from Buyer on account of the same.

ARTICLE 5. INSPECTION OF PROPERTIES

5.1 Physical and Environmental Inspection. After execution of this Agreement, Seller shall permit Buyer and its authorized representatives reasonable physical access to the Properties, at times approved by Seller and at Buyer's sole cost, risk and expense, for the purposes of inspecting the same and conducting such tests, examinations, investigations and assessments as may be reasonable and necessary to evaluate the physical and environmental condition of the Properties. Buyer shall repair any damage to the Properties resulting from its inspection and shall defend and indemnify the "Seller Group" (hereinafter defined) from any and all losses, liabilities, damages, expenses, costs, obligations and claims of whatsoever nature arising from Buyer inspecting the Properties, including, without limitation, (i)all claims for personal injury to or death of employees of Buyer, its agents, contractors, subcontractors or invitees and/or damage to the property of Buyer or others acting on behalf of Buyer, except to the extent caused by the negligence of Seller and regardless of the condition of the Properties, and (ii)all claims for personal injury to or death of employees of Seller or third parties and damage to the property of Seller or third parties, to the extent caused by the negligence, gross negligence or willful misconduct of Buyer.

5.2Environmental Defects.

5.2.1Inspection and Test Results. Buyer agrees to provide Seller with a copy of any and all environmental inspections and assessments, including, without limitation, all

written reports, data and conclusions. Buyer and Seller shall keep any and all data or information acquired by all such examinations and results of all analysis of such data and information strictly confidential and not disclose same to any person or agency without the prior written approval of the other party, unless required to do so by applicable Law or by the order of a court or regulatory agency.

Notwithstanding the foregoing, Buyer may disclose such data and information to its employees, officers, agents, advisors, consultants and attorneys and those of any lending institution financing Buyer's acquisition of the Properties for the sole purpose of evaluating the Properties in connection with the transaction contemplated hereby and only to the extent such disclosure is reasonably necessary for such purpose. In connection with the foregoing, Buyer shall ensure that all such persons comply with the restrictions on the disclosure and use of the data and information set forth herein. The foregoing obligation of confidentiality shall survive for five (5) years after the Closing; provided, however, that Buyer may disclose such data and information to prospective purchasers of interests in the Properties so long as each such prospective purchaser shall have duly executed a written agreement in which it undertakes obligations of confidentiality and non-disclosure with respect to the information and data no less stringent than those contained herein. The obligations set forth in this Section 5.2.1 that are imposed on the Buyer shall survive the termination or expiration of this Agreement without closing.

5.2.2 Notice of Environmental Defects. Prior to one hundred eighty (180) days after the Closing Date (the "Environmental Inspection Period"), Buyer shall review the inspection and testing results of the Properties and determine if any "Environmental Defect" (hereinafter defined) exists with respect to the Properties. An "Environmental Defect" shall mean an Environmental Claim attributable to or arising out of a violation of any Environmental Law (i) in effect on the Effective Time and applicable to conditions prior to the Closing Date, (ii) that is made known to Buyer prior to the expiration of the Environmental Inspection Period and (iii) to which prompt remedial or corrective action is required or would be undertaken by a prudent operator of oil and gas properties. Prior to the expiration of the Environmental Inspection Period, Buyer shall notify Seller in writing of any Environmental Defects with respect to the Properties, and the estimated value of any such Environmental Defects (e.g. the estimated cost of remediating or correcting such Environmental Defects). In the event such notice is not timely delivered, all Environmental Defects of which Buyer has notice as of such date shall be deemed waived for all purposes and Buyer shall thereafter have no right to claim Environmental Defects pursuant to this Section 5.2; and in the event the Environmental Defect notice is timely delivered, all Environmental Defects of which Buyer has notice as of such date and are not claimed in such notice shall be deemed waived for all purposes, subject, however, to Section 5.2.6 hereof.

5.2.3 Rights and Remedies for Environmental Defects Identified Prior to Closing. (a) With respect to any Environmental Defect affecting the Properties of which Seller is given notice in writing at least five (5) days before Closing (the "Pre-Closing

Notification Period”), Buyer may (i) request Seller to cure the Environmental Defect, but Seller shall have no obligation to cure the Environmental Defect, or (ii) request an adjustment to the Purchase Price equal to the estimated value of the Environmental Defect. If Seller and Buyer are unable to agree no later than three (3) Business Days before Closing on curative measures or an adjustment to the Purchase Price with respect to any such Environmental Defect, the parties shall have the rights and remedies set forth in subpart (b) of this Section 5.2.3.

(b) The rights and remedies of the parties with respect to any Environmental Defects for which the parties cannot agree on curative measures or a Purchase Price adjustment are as follows:

(i) If the aggregate value of all Environmental Defects is less than or equal to One Hundred Twenty-Five Thousand Dollars (US \$125,000), the parties shall be obligated to proceed with Closing as to all of the Properties without curative action by Seller for all such Environmental Defects and without an adjustment to the Purchase Price.

(ii) If the aggregate value of the Environmental Defects exceeds One Hundred Twenty-Five Thousand Dollars (US \$125,000), and the parties agree with respect to the existence of such Environmental Defects and the value thereof, the Purchase Price shall be reduced by the positive difference between the agreed upon value of the Environmental Defects and One Hundred Twenty-Five Thousand Dollars (US \$125,000), and the parties shall be obligated to proceed with Closing, subject to the termination rights of the parties under subpart (iv) of this Section 5.2.3(b).

(iii) If the aggregate value of all Environmental Defects exceeds One Hundred Twenty-Five Thousand Dollars (US \$125,000) and the parties cannot agree with respect to the existence of and/or the value of the Environmental Defects, the parties may refer the matter to a mutually agreed upon third party expert for determination of the existence of and/or the value of the Environmental Defects. The determination of such expert shall be binding on the parties, and the Purchase Price shall be reduced by the positive difference between the determined value of the Environmental Defects and One Hundred Twenty-Five Thousand Dollars (US \$125,000). The parties shall be obligated to proceed with Closing, subject to the termination rights of the parties under subpart (iv) of this Section 5.2.3(b).

(iv) If the aggregate value of the Environmental Defects equals or exceeds twenty percent (20%) of the Purchase Price, either party may terminate this Agreement, and neither party shall have any further obligation to conclude the transfer of the Properties under this Agreement. However, the right of termination

under this subpart (iv) must be exercised no later than two (2) Business Days before Closing, after which both parties shall be deemed to have waived their termination rights under this subpart (iv) in connection with Environmental Defects.

5.2.4 Rights and Remedies for Environmental Defects Identified Post-Closing. With respect to any Environmental Defects affecting the Properties of which Seller is notified in accordance with Section 5.2.2 hereof after the Pre-Closing Notification Period, but before the expiration of the Environmental Inspection Period, Seller shall, within six (6) months after the expiration of the Environmental Inspection Period, at its election, either:

- (a) Remediate the Environmental Defect or reimburse Buyer for the agreed cost thereof, but only to the extent the value of all such Environmental Defects exceeds One Hundred Twenty-Five Thousand Dollars (\$125,000); or
- (b) Refund the portion of the Purchase Price allocated to the Property or Properties affected thereby and accept a reconveyance of such Property or Properties from Buyer by instrument in substantially the same form as the Assignment and Bill of Sale and subject only to the Permitted Encumbrances; provided, however, that, if the aggregate value of all previously identified Environmental Defects does not exceed One Hundred Twenty-Five Thousand Dollars (\$125,000), the refund to be made by Seller for the affected Property or Properties under this Subsection 5.2.4(b) shall be the positive difference, if any, between (i) the sum of the aggregate value of all previously identified Environmental Defects and the portion of the Purchase Price allocated to such Property or Properties on Exhibit F and (ii) One Hundred Twenty-Five Thousand Dollars.

5.2.5 Agreed Remediation. In addition to the foregoing, Seller agrees to perform the remediation described on Exhibit M within six (6) months after the expiration of the Environmental Inspection Period.

5.2.6 No Waiver. Failure of Buyer to give notice to Seller of an Environmental Defect within the Environmental Inspection Period shall not prejudice nor result in a waiver of Buyer's rights pursuant to Section 8.3.

ARTICLE 6. ACCOUNTING

6.1 Revenues, Expenses and Capital Expenditures. All Hydrocarbons produced prior to the Effective Time (irrespective of whether payment for the same has been made or received) which are attributable to the Properties shall belong to Seller, and all such Hydrocarbons produced from and after the Effective Time shall belong to Buyer. Seller shall be entitled to all

revenues and related accounts receivable attributable to the ownership or operation of the Properties, and shall be responsible for all costs and expenses and related accounts payable attributable to the ownership or operation of the Properties, to the extent they relate to the time prior to the Effective Time. Buyer shall be entitled to all revenues and related accounts receivable attributable to the ownership or operation of the Properties, and shall be responsible for all costs and expenses and related accounts payable attributable to the ownership or operation of the Properties, to the extent they relate to the time from and after the Effective Time. The actual amounts or values associated with the above shall be accounted for in the Final Accounting Settlement. At Closing Seller shall transfer to Buyer, and Buyer shall assume, Seller's suspense funds associated with the acquired Properties as of the Effective Time, and these funds shall be accounted for in the Final Accounting Settlement.

6.2 Taxes. All taxes and assessments, including without limitation, excise, ad valorem, property, production and severance taxes and any other federal, state and local taxes and assessments attributable to the ownership or operation of the Properties prior to the Effective Time shall remain Seller's responsibility, and all deductions, credits and refunds pertaining to the aforementioned taxes and assessments, no matter when received, shall belong to Seller. All taxes and assessments, including without limitation, excise, ad valorem, property, production and severance taxes and any other federal, state and local taxes and assessments attributable to the ownership or operation of the Properties after the Effective Time shall be Buyer's responsibility, and all deductions, credits and refunds pertaining to the aforementioned taxes and assessments, no matter when received, shall belong to Buyer. The actual amounts or values associated with the above, if any, shall be accounted for in the Final Accounting Settlement. The parties agree that the transaction contemplated herein is an occasional sale of assets by Seller in which Seller does not trade in the ordinary course of its business. Accordingly, the parties will take commercially reasonable actions to establish the occasional sale exemption from any sales tax associated with the transaction contemplated herein. Notwithstanding the foregoing, Buyer shall be solely responsible for all transfer, sales, use or similar taxes resulting from or associated with the transaction contemplated under this Agreement.

6.3 Obligations and Credits. Any and all prepaid insurance premiums, utility charges, taxes, rentals and any other prepaids, to the extent applicable to periods of time after the Effective Time and to the extent attributable to the Properties shall be reimbursed to Seller by Buyer; and accrued payables applicable to periods of time prior to the Effective Time, if any, and attributable to the Properties shall be the responsibility of Seller. The actual amounts or values associated with the above shall be accounted for in the Final Accounting Settlement.

6.4 Gas Imbalances. Seller's estimate of the aggregate gas imbalance as of the Effective Time for all the Properties is 33,826 mcf under produced (cumulative working interests), as more particularly set forth for each of the Properties on Exhibit G. In the event such gas imbalance estimate is revised by Seller prior to Closing, Seller shall provide Buyer with a revised gas imbalance schedule for all the Properties as of the Effective Time. There shall be a Purchase Price adjustment at Closing for the volumetric difference in the estimated and revised

imbalance calculated on Seller's net revenue interest at a price of \$1.00 per mcf. To the extent that there is any difference between Seller's actual aggregate gas imbalance as of the Effective Time and the imbalance position settled at Closing, then an adjustment shall be made at the \$1.00 per net mcf rate in the Final Accounting Settlement. There shall be no further gas imbalance adjustments after the Final Settlement Date. In the event of a Title Defect affecting all or a portion of the Properties, the aggregate gas imbalance shown above shall be adjusted to take into account the affected Property. Any Purchase Price adjustments for gas imbalances shall be made only on those Properties purchased by Buyer.

6.5 Miscellaneous Accounting.

6.5.1 A preliminary Closing statement will be prepared for Closing, as provided in Section 16.1.

6.5.2 In addition to the items set forth in Sections 6.1 and 6.2, any other amounts due between Buyer and Seller related to the ownership or operation of the Properties shall be accounted for in the Final Accounting Settlement.

6.6 Final Accounting Settlement. As soon as reasonably practicable, but in no event later than one hundred twenty (120) Days after Closing, Seller shall deliver to Buyer a post-Closing statement setting forth a detailed final calculation of all post-Closing adjustments applicable to the period between the Effective Time and the Closing Date ("Final Accounting Settlement"). As soon as reasonably practicable, but in no event later than thirty (30) Days after Buyer receives the post-Closing statement, Buyer shall deliver to Seller a written report containing any changes Buyer proposes to be made to such statement. As soon as reasonably practicable, but in no event later than thirty (30) Days after Seller receives Buyer's proposed changes to the post-Closing statement, the parties shall meet and undertake to agree on the post-Closing adjustments. If the parties fail to agree on the post-Closing adjustments, resolution shall be handled in accordance with Section 6.8. The date upon which all amounts associated with the Final Accounting Settlement are agreed to by the parties, whether by decision of the Accounting Referee or otherwise, shall be herein called the "Final Settlement Date". Any amounts owed by either party to the other as a result of such post-Closing adjustments shall be paid within five (5) Business Days after the Final Settlement Date.

6.7 Post-Final Accounting Settlement. Any revenues received or costs and expenses paid by Buyer after the Final Accounting Settlement which are attributable to the ownership or operation of the Properties prior to the Effective Time shall be billed to or reimbursed to Seller, as appropriate. Any revenues received or costs and expenses paid by Seller after the Final Accounting Settlement which are attributable to the ownership or operation of the Properties after the Effective Time shall be billed to or reimbursed by Buyer, as appropriate.

6.8 Audit Rights. In order to verify the information provided by the parties under this Article 6, Buyer and Seller shall each have the right to conduct, at such party's sole expense, an

audit of the other party's records relating thereto for a period of one (1) year after the Closing Date. **Objections or exceptions which are not raised within such one-year audit period shall be conclusively deemed to be waived by the parties for all purposes, and neither party shall have the right to make a claim against the other party or seek indemnification or reimbursement from the other party associated with the same.** If within such fifteen (15) Days after receiving the results of a party's audit conducted in accordance with this Article, the parties still cannot reach agreement, the disputed items shall be resolved by submitting the same to KPMG LLP, or if such firm declines to act in such capacity, by such other firm of independent nationally recognized accountants mutually acceptable to the parties (the "Accounting Referee"). The Accounting Referee shall be instructed to resolve the accounting dispute(s) within thirty (30) Days after having the relevant materials submitted to it for review. The decision of the Accounting Referee shall be binding and non-appealable by the parties. The fees and expenses associated with the Accounting Referee shall be borne equally by Buyer and Seller.

ARTICLE 7. CASUALTY AND CONDEMNATION

If a substantial part of the Properties shall be (a) destroyed prior to Closing by a Casualty Loss, or (b) taken in condemnation or if proceedings for such purposes shall be pending (collectively referred to as a "Taking"); then either Buyer or Seller may terminate this Agreement prior to the Closing. For the purpose of this Article 7, the term "substantial" shall be defined as twenty percent (20%) of the unadjusted Purchase Price. If either party terminates this Agreement in accordance with this Section, neither party shall have any further obligations, except as provided in this Article and in Section 15.2.1.

If neither party terminates this Agreement, this Agreement shall remain in full force and effect, and Seller and Buyer shall attempt to agree on a reduction in the Purchase Price, reflecting the reduction in the value of the Properties affected by the Casualty Loss and/or Taking. If the parties cannot agree on a reduction, the Seller's good faith calculation shall be used for purposes of Closing. Notwithstanding anything herein to the contrary, in no event shall either party have any obligations hereunder with respect to any Casualty Loss and/or Taking except to the extent that the value of all such Casualty Losses and/or Takings exceed in the aggregate Fifty Thousand Dollars (US \$50,000), and Buyer hereby waives all downward adjustments to the Purchase Price for all Casualty Losses and/or Takings the cumulative value of which is \$50,000 or less. Unless otherwise agreed by the parties, Seller shall retain any and all sums paid to Seller, unpaid awards, insurance proceeds and other payments associated with or attributable to Casualty Losses and/or Takings.

If there is a dispute over the value of any Casualty Loss and/or Taking, Buyer may submit the matter to arbitration in accordance with Article 13 within sixty (60) Days after Closing, or if a party terminates this Agreement under this provision and the other party disputes the party's right to terminate hereunder, the disputing party may submit the matter to arbitration in accordance with Article 13 within sixty (60) Days after the date which had been scheduled for Closing. **If Buyer disputes the Purchase Price adjustment for any Casualty Loss and/or Taking or a**

party disputes termination, and Buyer or the disputing party, as applicable, does not initiate an arbitration proceeding to resolve the matter within the applicable time periods specified in the foregoing sentence, such party in either case shall be deemed to have waived its rights with respect to such dispute.

ARTICLE 8. INDEMNITIES

8.1 Seller's Indemnity Obligations (excluding Environmental Claims). EXCEPT FOR ENVIRONMENTAL CLAIMS WHICH SHALL BE HANDLED IN ACCORDANCE WITH SECTION 8.3, SELLER SHALL RELEASE BUYER AND BUYER'S AFFILIATES AND THEIR RESPECTIVE OFFICERS, DIRECTORS AND EMPLOYEES (COLLECTIVELY, THE "BUYER GROUP") FROM AND SHALL FULLY PROTECT, INDEMNIFY, AND DEFEND BUYER GROUP FROM AND AGAINST ANY AND ALL CLAIMS AND ANY AND ALL OCCURRENCES AND CONDITIONS WHICH WOULD CONSTITUTE CLAIMS BUT WHICH ARE ASSERTED BY SELLER, RELATING TO, ARISING OUT OF, OR CONNECTED WITH SELLER'S OWNERSHIP OR OPERATION OF THE PROPERTIES PRIOR TO THE EFFECTIVE TIME, REGARDLESS OF ANY NEGLIGENCE OF ACT OR OMISSION BY BUYER GROUP; PROVIDED, HOWEVER, THAT PROPER NOTICE UNDER SECTION 8.5 SHALL HAVE BEEN SUBMITTED TO SELLER WITHIN SIX (6) MONTHS AFTER THE CLOSING DATE, AND FURTHER PROVIDED THAT BUYER SHALL BEAR SOLE RESPONSIBILITY FOR THE COSTS ASSOCIATED WITH ALL SUCH CLAIMS (IN AGGREGATE) UP TO ONE HUNDRED TWENTY-FIVE THOUSAND DOLLARS (US \$125,000).

8.2 Buyer's Indemnity Obligations (excluding Environmental Claims). EXCEPT FOR ENVIRONMENTAL CLAIMS WHICH SHALL BE HANDLED IN ACCORDANCE WITH SECTION 8.3 AND EXCEPT AS EXPRESSLY SET FORTH IN THIS AGREEMENT, BUYER SHALL RELEASE SELLER AND SELLER'S AFFILIATES AND THEIR RESPECTIVE OFFICERS, DIRECTORS AND EMPLOYEES (COLLECTIVELY, THE "SELLER GROUP") FROM AND SHALL FULLY PROTECT, INDEMNIFY, AND DEFEND THE SELLER GROUP FROM AND AGAINST ANY AND ALL CLAIMS AND ANY AND ALL OCCURRENCES AND CONDITIONS WHICH WOULD CONSTITUTE CLAIMS BUT WHICH ARE ASSERTED BY BUYER RELATING TO, ARISING OUT OF, OR CONNECTED WITH THE OWNERSHIP OR OPERATION OF THE PROPERTIES (i) PERTAINING TO THE PERIOD AFTER THE EFFECTIVE TIME, AND (ii) PERTAINING TO THE PERIOD PRIOR TO THE EFFECTIVE TIME, UNLESS SUCH CLAIMS OR OCCURRENCES AND CONDITIONS SHALL HAVE BEEN SUBMITTED TO SELLER IN ACCORDANCE WITH THE NOTICE PROVISIONS HEREOF WITHIN SIX (6) MONTHS AFTER THE CLOSING DATE AND ARE IN THE AGGREGATE GREATER THAN ONE HUNDRED TWENTY-FIVE THOUSAND DOLLARS (US \$125,000). THIS INDEMNITY SHALL

APPLY REGARDLESS OF ANY NEGLIGENCE OF ACT OR OMISSION BY SELLER GROUP.

8.3 Environmental Claims. BUYER SHALL RELEASE SELLER GROUP AND SHALL FULLY PROTECT, INDEMNIFY, AND DEFEND SELLER GROUP FROM AND AGAINST ANY AND ALL ENVIRONMENTAL CLAIMS AND ANY AND ALL OCCURRENCES AND CONDITIONS WHICH WOULD CONSTITUTE ENVIRONMENTAL CLAIMS BUT WHICH ARE ASSERTED BY BUYER PERTAINING TO THE PROPERTIES AND RELATING TO THE PERIOD FROM AND AFTER THE EFFECTIVE TIME. SELLER SHALL RELEASE BUYER GROUP AND SHALL FULLY PROTECT, INDEMNIFY, AND DEFEND BUYER GROUP FROM AND AGAINST ALL ENVIRONMENTAL CLAIMS PERTAINING TO THE PROPERTIES AND RELATING TO THE PERIOD PRIOR TO THE EFFECTIVE TIME THAT ARE IN THE AGGREGATE GREATER THAN AN AMOUNT EQUAL TO THE DIFFERENCE BETWEEN (i)ONE HUNDRED TWENTY-FIVE THOUSAND DOLLARS (US \$125,000) AND (ii)THE AGGREGATE VALUE OF ALL ENVIRONMENTAL DEFECTS UNDER SECTION 5.2 ABOVE, IT BEING AGREED THAT BUYER SHALL BEAR SOLE RESPONSIBILITY FOR THE COSTS ASSOCIATED WITH ALL ENVIRONMENTAL DEFECTS UNDER SECTION 5.2 ABOVE AND ALL ENVIRONMENTAL CLAIMS UNDER THIS SECTION 8.3 (IN AGGREGATE) UP TO ONE HUNDRED TWENTY-FIVE THOUSAND DOLLARS (US \$125,000).

8.4Asbestos and NORM. The parties acknowledge that the Properties may contain asbestos and/or NORM, and that special procedures may be required for the assessment, remediation, removal, transportation or disposal of asbestos and NORM. Buyer agrees to assume any and all liability associated with or attributable to the assessment, remediation, removal, transportation and disposal of the asbestos or NORM associated with or attributable to the Properties and shall conduct said activities in accordance with all applicable Laws.

8.5 Notice and Cooperation. If a Claim is asserted against a party for which the party would be liable under the provisions of this Agreement, it is a condition precedent to the indemnifying party's obligations hereunder that the indemnified party gives the indemnifying party written notice of such Claim setting forth full particulars of the Claim, as known by the indemnified party, including a copy of the Claim (if it was a written Claim.) The indemnified party shall make a good faith effort to notify the indemnifying party within one (1) month of receipt of a Claim and shall in all events effect such notice within such time as will allow the indemnifying party to defend against such Claim and no later than three (3)calendar months after receipt of the Claim by the indemnified party. The notice of a Claim given hereunder is referred to as a "Claim Notice."

8.6 Defense of Claims.

8.6.1 Counsel. Upon receipt of a Claim Notice, the indemnifying party may assume the defense thereof with counsel selected by the indemnifying party and reasonably satisfactory to the indemnified party. The indemnified party shall cooperate in all reasonable respects in such defense. If any Claim involves Claims with respect to which Buyer indemnifies Seller and also Claims for which Seller indemnifies Buyer, each party shall have the right to assume the defense of and hire counsel for that portion of the Claim for which it has liability. The indemnified party shall have the right to employ separate counsel in any Claim and to participate in the defense thereof, provided the fees and expenses of counsel employed by an indemnified party shall be at the expense of the indemnified party unless otherwise agreed between the parties.

8.6.2 Settlement. If the indemnifying party does not notify the indemnified party within the earlier to occur of: (a) the time a response is due in the relevant litigation matter, or (b) three (3) calendar months after receipt of the Claim Notice, that the indemnifying party elects to undertake the defense thereof, the indemnified party has the right to defend, at the sole expense of the indemnifying party, the Claim with counsel of its own choosing, subject to the right of the indemnifying party to assume the defense of any Claim at any time prior to settlement or final determination thereof at the indemnifying party's sole expense. In such event, the indemnified party shall send a written notice to the indemnifying party of any proposed settlement of any Claim, which settlement the indemnifying party may accept or reject, in its reasonable judgment, within thirty (30) Days of receipt of such notice, unless the settlement offer is limited to a shorter period of time in which case the indemnifying party shall have such shorter period of time in which to accept or reject the proposed settlement. Failure of the indemnifying party to accept or reject such settlement within the thirty (30) Day period, or such shorter period of time, if applicable, shall be deemed to be its rejection of such settlement. The indemnified party may settle any matter over the objection of the indemnifying party but shall in so doing be deemed to have waived any right to indemnity therefor as to (and only as to) liabilities with respect to which the indemnifying party has recognized its liability.

8.7 Waiver of Certain Damages. Each of the parties hereby waives, and agrees not to seek, indirect, consequential, punitive, exemplary or special damages of any kind with respect to any Claim, occurrence, condition or dispute, arising out of or relating to this Agreement or breach hereof; provided, however, that this provision does not diminish or affect in any way the parties' rights and obligations under any indemnities provided for in this Agreement.

8.8. Limitation on Indemnities. In no event shall an indemnifying party have any obligation of indemnification to the other party, if the Claim, occurrence, condition or dispute for which indemnity is sought was caused by the gross negligence or willful

misconduct on the part of the indemnified party and/or its officers, directors, employees, agents, contractors, subcontractors, Affiliates or predecessors. Notwithstanding anything contained herein to the contrary, the indemnities provided for in this Agreement shall be enforceable only by the parties hereto and not by either party's successors or assigns, it being expressly agreed that such indemnities shall be deemed a personal covenant between Seller and Buyer and not a covenant that runs with the Properties.

ARTICLE 9. WARRANTIES AND DISCLAIMERS

9.1 Special Warranty of Title. Seller shall warrant and defend title to the Properties conveyed to Buyer against every person whomsoever lawfully claiming the Properties or any part thereof by, through or under Seller, but not otherwise, and subject to the Permitted Encumbrances.

9.2 Disclaimer – Representations and Warranties. BUYER ACKNOWLEDGES AND AGREES THAT THE PROPERTIES ARE BEING SOLD, ASSIGNED AND CONVEYED FROM SELLER TO BUYER “AS-IS, WHERE-IS”, AND WITH ALL FAULTS IN THEIR PRESENT CONDITION AND STATE OF REPAIR, WITHOUT RECOURSE. EXCEPT AS EXPRESSLY SET FORTH IN THIS AGREEMENT, SELLER HEREBY DISCLAIMS ANY AND ALL REPRESENTATIONS AND WARRANTIES CONCERNING THE PROPERTIES, EXPRESS, STATUTORY, IMPLIED OR OTHERWISE, INCLUDING WITHOUT LIMITATION, ANY WARRANTY OF TITLE (EXCEPT AS SET FORTH IN SECTION 9.1), THE QUALITY OF HYDROCARBON RESERVES, THE QUANTITY OF HYDROCARBON RESERVES, THE AMOUNT OF REVENUES, THE AMOUNT OF OPERATING COSTS, CONDITION (PHYSICAL OR ENVIRONMENTAL), QUALITY, COMPLIANCE WITH APPLICABLE LAWS, ABSENCE OF DEFECTS (LATENT OR PATENT), SAFETY, STATE OF REPAIR, MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND BUYER EXPRESSLY RELEASES SELLER FROM THE SAME.

9.3 Disclaimer – Statements and Information . EXCEPT AS EXPRESSLY SET FORTH IN THIS AGREEMENT, SELLER DISCLAIMS ANY AND ALL LIABILITY AND RESPONSIBILITY FOR AND ASSOCIATED WITH THE QUALITY, ACCURACY, COMPLETENESS OR MATERIALITY OF THE RECORDS AND ANY OTHER INFORMATION PROVIDED AT ANY TIME (WHETHER ORAL OR WRITTEN) TO BUYER, ITS OFFICERS, AGENTS, EMPLOYEES AND REPRESENTATIVES IN CONNECTION WITH THE TRANSACTION CONTEMPLATED HEREIN, INCLUDING WITHOUT LIMITATION, QUALITY OF HYDROCARBON RESERVES, QUANTITY OF HYDROCARBON RESERVES, AMOUNT OF REVENUES, AMOUNT OF OPERATING COSTS, FINANCIAL DATA, CONTRACT DATA, ENVIRONMENTAL CONDITION OF THE PROPERTIES, PHYSICAL CONDITION OF THE PROPERTIES AND CONTINUED FINANCIAL

VIABILITY OF THE PROPERTIES, AND BUYER EXPRESSLY RELEASES SELLER FROM THE SAME.

ARTICLE 10. SELLER'S REPRESENTATIONS

Seller represents to Buyer that on the date hereof and as of the Closing Date:

10.1 Organization and Good Standing. Seller is a corporation duly organized, validly existing and in good standing under the Laws of the State of Arkansas, and has all requisite corporate power and authority to own and lease the Properties. Seller is duly licensed or qualified to do business as a foreign corporation and is in good standing in all jurisdictions in which the Properties are located.

10.2 Corporate Authority; Authorization of Agreement. Seller has all requisite corporate power and authority to execute and deliver this Agreement, to consummate the transactions contemplated herein and to perform all of the terms and conditions to be performed by it as provided for in this Agreement. The execution and delivery of this Agreement by Seller, the performance by Seller of all of the terms and conditions to be performed by it and the consummation of the transactions contemplated herein have been duly authorized and approved by all necessary corporate action. This Agreement has been duly executed and delivered by Seller and constitutes the valid and binding obligation of Seller, enforceable against it in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency or other Laws relating to or affecting the enforcement of creditors' rights and general principles of equity (regardless of whether such enforceability is considered in a proceeding at law or in equity).

10.3 No Violations. The execution and delivery of this Agreement by Seller does not, and the fulfillment and compliance with the terms and conditions hereof and the consummation of the transactions contemplated herein, will not:

- (a) Conflict with or require the consent of any person or entity under any of the terms, conditions or provisions of the certificate of incorporation or bylaws of Seller;
- (b) Violate any provision of, or require any filing, consent or approval under any Law applicable to or binding upon Seller (assuming receipt of all consents and approvals of governmental entities customarily obtained subsequent to the transfers of title);
- (c) Conflict with, result in a breach of, constitute a default under or constitute an event that with notice or lapse of time, or both, would constitute a default under, accelerate or permit the acceleration of the performance required by, or require any consent, authorization or approval under, (i) any mortgage, indenture, loan, credit agreement or other agreement, evidencing indebtedness for borrowed money to which

Seller is a party or by which Seller is bound or (ii) any order, judgment or decree of any governmental entity or tribal authority; or (d) Result in the creation or imposition of any lien or encumbrance upon the Properties.

10.4 Absence of Certain Changes. Between the Effective Time and the execution date hereof, there has not been:

- (a) A sale, lease or other disposition of any material part of the Properties, other than the sale of Hydrocarbons in the ordinary course of business, consistent with prior practices of Seller;
- (b) A mortgage, pledge or grant of a lien or security interest in any of the Properties; or
- (c) A contract or commitment to do any of the foregoing.

10.5 Operating Costs. To the best of Seller's knowledge, all costs incurred in connection with the operation of the Properties have been fully paid and discharged by Seller, except normal expenses incurred in operating the Properties within the previous sixty (60) Days or as to which Seller has not yet been billed or as to which Seller is disputing in good faith.

10.6 Litigation and Other Disputes. Seller shall retain liability for the matters listed on Exhibit E. Except for the matters listed on Exhibit E, there is no action, suit or proceeding pending or, to the best of Seller's knowledge, threatened against Seller or the Properties which would reasonably be expected to have a material adverse effect on Buyer or Buyer's interest in the Properties after Closing or to prevent the consummation of the transaction contemplated by this Agreement. For purposes of this provision, "material" means an impact of greater than Fifty Thousand Dollars (US \$50,000) in the aggregate.

10.7 Bankruptcy. There are no bankruptcy, reorganization or receivership proceedings pending, being contemplated by or, to the best of Seller's knowledge, threatened against Seller.

10.8 Leases. To the best of Seller's knowledge, (i) the Leases have been maintained in material compliance with their terms, are valid, binding and in full force and effect, (ii) there are no defaults by Seller in the performance of any of the material terms and conditions of the Leases and (iii) no event has occurred that with the lapse of time or action or inaction by any party would result in a material violation of the Leases or a default thereunder. To the best of Seller's knowledge, all royalties (including shut-in payments), rental, deposits and other amounts due on the Properties have been properly and timely paid.

10.9 Hydrocarbon Sales; Imbalances. Except as otherwise provided in Section 6.4, Seller has not been nor will Buyer after the Effective Time be obligated by virtue of any prepayment made under any gas transportation, production sales contract or any other contract containing a "take or pay" clause, or under any gas balancing, deferred production or similar arrangement to deliver oil, gas or other minerals produced from or allocated to any of the Properties at such future time without receiving full payment therefor at the time of delivery.

10.10 Existing Commitments. Except as described on Exhibit H and except for any commitment for expenditures of less than \$10,000, there are no existing commitments or obligations to pay costs or expenses for drilling, completing, equipping, deepening, side tracking, reworking or other similar costs or expenses arising from or relating to the ownership of the Properties. Except as otherwise provided in the Material Contracts, there are no obligations or commitments presently existing under which Seller's interest in the Properties will be altered due to the passage of time, the collection of a specified sum of money (including, for example, non-consent operations and back-in obligations) or other reason.

10.11 Compliance With Law . Except for those matters disclosed on Exhibit and such other matters as would not have a material adverse effect on the value of the Properties, Seller (i) is in material compliance with all Laws applicable to Seller or those Properties that are operated by Seller and (ii) has not received notice of and is not aware of any facts, conditions or circumstances relating to the ownership or operation of the Properties that could reasonably be expected to give rise to any claim or assertion that Seller, the Properties or the ownership or operation thereof is not in material compliance with any Law applicable to Seller or the Properties. For purposes of this provision, "material" means an impact of greater than One Hundred Twenty-Five Thousand Dollars (US \$125,000) in the aggregate.

10.12 Availability of Records. To the best of Seller's knowledge, Seller has provided Buyer with access to all Records in Seller's possession in connection with Buyer's due diligence review of the Properties.

10.13 Limitation on Representations. The representations contained in Sections 10.1 through 10.4 shall survive Closing indefinitely. The representations contained in Sections 10.5 through 10.12 shall survive Closing for a period of six (6) months after the Closing Date and shall thereupon terminate.

ARTICLE 11. BUYER'S REPRESENTATIONS

Buyer represents to Seller that on the date hereof and as of the Closing Date:

11.1 Organization and Good Standing. Buyer is a limited liability company duly organized, validly existing and in good standing under the Laws of the State of Oklahoma and has all requisite power and authority to own and lease the Properties. Buyer is duly licensed or

qualified to do business as a foreign corporation and is in good standing in all jurisdictions in which the Properties are located.

11.2 Corporate Authority; Authorization of Agreement. Buyer has all requisite power and authority to execute and deliver this Agreement, to consummate the transactions contemplated herein and to perform all the terms and conditions to be performed by it as provided for in this Agreement. The execution and delivery of this Agreement by Buyer, the performance by Buyer of all the terms and conditions to be performed by it and the consummation of the transactions contemplated herein have been duly authorized and approved by all necessary action. This Agreement has been duly executed and delivered by Buyer and constitutes the valid and binding obligation of Buyer, enforceable against it in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency or other Laws relating to or affecting the enforcement of creditors' rights and general principles of equity (regardless of whether such enforceability is considered in a proceeding at law or in equity).

11.3 No Violations. The execution and delivery of this Agreement by Buyer does not, and the fulfillment and compliance with the terms and conditions hereof and the consummation of the transactions contemplated herein, do not:

- (a) Conflict with or require the consent of any person or entity under any of the terms, conditions or provisions of the articles of organization or other organizational documents of Buyer;
- (b) Violate any provision of, or require any filing, consent or approval under any Law applicable to or binding upon Buyer; or
- (c) Conflict with, result in a breach of, constitute a default under or constitute an event that with notice or lapse of time, or both, would constitute a default under, accelerate or permit the acceleration of the performance required by, or require any consent, authorization or approval under, (i) any mortgage, indenture, loan, credit agreement or other agreement evidencing indebtedness for borrowed money to which Buyer is a party or by which Buyer is bound, or (ii) any order, judgment or decree of any governmental entity or tribal authority.

11.4 SEC Disclosure. Buyer is an experienced and knowledgeable investor and operator in the oil and gas business. Buyer is acquiring the Properties for its own account for use in its trade or business, and not with a view toward or for sale in connection with any distribution thereof, nor with any present intention of making a distribution thereof within the meaning of the Securities Act of 1933, as amended.

11.5 Independent Evaluation. As of Closing, Buyer represents that it is sophisticated in the evaluation, purchase, operation and ownership of oil and gas properties and that in making its decision to enter into this Agreement and to consummate

the transaction contemplated herein, Buyer has relied and shall rely solely on its own independent investigation and evaluation of the Properties and has satisfied itself as to the physical condition and environmental condition of the Properties.

11.6 Buyer's Reliance. Buyer acknowledges and agrees that it is entitled to rely only on the express representations and warranties set forth in this Agreement.

11.7 Qualified Buyer. Buyer possesses all required governmental licenses, permits, bonds, certificates, orders and authorizations necessary to own and/or operate the Properties, except those customarily obtained after the sale or conveyance of the Properties.

11.8 Limitation on Representations. The representations contained in Sections 11.1 through 11.4 shall survive Closing indefinitely. The representations contained in Sections 11.5 through 11.7 shall survive Closing for a period of six (6) months after the Closing Date and shall thereupon terminate.

ARTICLE 12. ADDITIONAL AGREEMENTS

12.1 Covenants of Seller. From the date hereof until Closing, without first obtaining the consent of Buyer, Seller has not and will not:

- (a) waive any right of material value relating to the Properties;
- (b) convey, encumber, mortgage, abandon or pledge any of the Properties nor dispose of any of the Properties, other than the sale of production in the ordinary course of business and except as may be required in connection with the exercise of preferential rights affecting the Properties;
- (c) enter into, modify or terminate any contracts relating to the Properties, other than in the ordinary course of business;
- (d) vote to commit to any material project or material expenditure under any operating agreement affecting the Properties or elect to participate in any operation on the Properties requiring an expenditure of greater than Ten Thousand Dollars (US \$10,000) to Seller's interest, except to the extent required in an emergency to protect life or property from immediate harm or destruction; or
- (e) contract or commit itself to do any of the foregoing.

12.2 Notice of Loss. From the date hereof until Closing, Seller shall promptly notify Buyer of any loss or damage to the Properties, or any part thereof, known to Seller and in the aggregate exceeding Ten Thousand Dollars (US \$10,000) net to Seller's interest.

12.3 Operations Pending Closing. During the period from the Effective Time to the Closing Date, Seller shall continue to operate those Properties that are operated by Seller in the normal course of business in accordance with Seller's historical operating practices and using the same standard of care as is imposed on the "Operator" under the operating agreements applicable to such Properties.

12.4 Subsequent Operations. Seller makes no representations or warranties to Buyer as to the transferability or assignability of operatorship of the Properties. Buyer acknowledges that the rights and obligations associated with operatorship of the Properties are governed by the applicable agreement(s) and that operatorship of the Properties shall be decided in accordance with the terms of said agreement(s); provided, however, Seller agrees to provide reasonable assistance to Buyer (at no expense to Seller) in connection with Buyer's effort to be designated as operator of the Properties.

12.5 Buyer's Assumption of Obligations. Except as expressly set forth in this Agreement, Buyer agrees to assume and shall timely perform and discharge all duties and obligations of Seller relating to or arising out of the ownership of the Properties from and after the Effective Time, including, without limitation, all duties and obligations of Seller under all the Assumed Contracts, and Buyer shall indemnify and hold Seller harmless from and against any and all liabilities of whatsoever nature arising out of Buyer's failure to properly perform or discharge such duties and obligations. Buyer agrees to accept full responsibility for Seller's proportionate share of the costs and expenses associated with or attributable to the plugging and abandonment of all wells, and the removal of all equipment, platforms and facilities conveyed to Buyer under this Agreement and the remediation, restoration and clean up of the Properties. In conducting the duties and obligations contained in this Section 12.5, Buyer shall comply with the applicable Laws of all governmental entities and tribal authorities having appropriate jurisdiction.

12.6 Records. Within thirty (30) Days after Closing, Seller shall furnish to Buyer all Records which are maintained by Seller, provided, however, that Seller is entitled to retain copies of any or all such Records and to retain as long as needed, the originals of any Records required in connection with any litigation or other proceedings listed on Exhibit E. Buyer agrees to maintain the Records received from Seller, and any other records that Buyer may receive from the current operators of any of the Properties, in accordance herewith for a period of six (6) years after the Closing Date and to afford Seller reasonable access to as requested by Seller. If Buyer desires to dispose of any such records prior to the end of the six (6) year period, Buyer shall offer in writing to Seller to deliver such records to Seller; if Seller elects not to receive such records or fails to respond to Buyer's notice within thirty (30) Business Days after receipt thereof, then Buyer may dispose of such records within its discretion.

ARTICLE 13. ARBITRATION

ANY DISPUTE ARISING UNDER THIS AGREEMENT (“ARBITRABLE DISPUTE”) SHALL BE REFERRED TO AND RESOLVED BY BINDING ARBITRATION IN HOUSTON, TEXAS BY THREE (3) ARBITRATORS, IN ACCORDANCE WITH THE COMMERCIAL ARBITRATION RULES OF THE AMERICAN ARBITRATION ASSOCIATION; AND, TO THE MAXIMUM EXTENT APPLICABLE, THE FEDERAL ARBITRATION ACT (TITLE 9 OF THE UNITED STATES CODE). IF THERE IS ANY INCONSISTENCY BETWEEN THIS ARTICLE AND ANY STATUTE OR RULES, THIS ARTICLE SHALL CONTROL. ARBITRATION SHALL BE INITIATED (a) WITHIN THE APPLICABLE TIME LIMITS SET FORTH IN THIS AGREEMENT AND NOT THEREAFTER, PROVIDED THAT IF NO TIME LIMIT IS GIVEN, WITHIN THE TIME PERIOD ALLOWED BY THE APPLICABLE STATUTE OF LIMITATIONS, (b) BY ONE PARTY (“CLAIMANT”) GIVING WRITTEN NOTICE TO THE OTHER OR ADVERSARIAL PARTY (“RESPONDENT”) AND TO THE HOUSTON REGIONAL OFFICE OF THE AMERICAN ARBITRATION ASSOCIATION (“AAA”), ATTENTION: REGIONAL VICE PRESIDENT, WITH A COPY TO THE ADMINISTRATOR OF THE AAA, THAT THE CLAIMANT ELECTS TO REFER THE ARBITRABLE DISPUTE TO ARBITRATION, AND THAT THE CLAIMANT HAS APPOINTED AN ARBITRATOR, WHO SHALL BE IDENTIFIED IN SUCH NOTICE. THE RESPONDENT SHALL NOTIFY THE CLAIMANT AND THE AAA WITHIN TEN (10) DAYS AFTER RECEIPT OF CLAIMANT’S NOTICE, IDENTIFYING THE ARBITRATOR WHO THE RESPONDENT HAS APPOINTED. THE TWO (2) ARBITRATORS SO CHOSEN SHALL SELECT A THIRD ARBITRATOR WITHIN TEN (10) DAYS AFTER THE SECOND ARBITRATOR HAS BEEN APPOINTED. UPON FAILURE OF A PARTY TO ACT WITHIN THE TIME SPECIFIED FOR NAMING AN ARBITRATOR, SUCH ARBITRATOR SHALL BE APPOINTED BY THE ADMINISTRATOR’S DESIGNEE. SELLER SHALL PAY THE COMPENSATION AND EXPENSES OF THE ARBITRATOR NAMED BY OR FOR IT, BUYER SHALL PAY THE COMPENSATION AND EXPENSES OF THE ARBITRATOR NAMED BY OR FOR IT, AND SELLER AND BUYER SHALL EACH PAY ONE-HALF OF THE COMPENSATION AND EXPENSES OF THE THIRD ARBITRATOR, PROVIDED HOWEVER THAT ALL COSTS CAN BE ASSESSED AGAINST THE LOSING PARTY, IF THE ARBITRATORS SO DECIDE. ALL ARBITRATORS MUST BE NEUTRAL PARTIES WHO HAVE NEVER BEEN OFFICERS, DIRECTORS OR EMPLOYEES OF THE PARTIES OR ANY OF THEIR AFFILIATES, MUST HAVE NOT LESS THAN FIFTEEN (15) YEARS EXPERIENCE IN THE OIL AND GAS INDUSTRY, AND MUST HAVE A FORMAL FINANCIAL/ACCOUNTING, ENGINEERING OR LEGAL EDUCATION. THE HEARING SHALL BE COMMENCED WITHIN THIRTY (30) DAYS AFTER THE SELECTION OF THE ARBITRATORS. THE PARTIES AND THE ARBITRATORS SHALL PROCEED DILIGENTLY AND IN GOOD FAITH IN ORDER THAT THE

ARBITRAL AWARD SHALL BE MADE AS PROMPTLY AS POSSIBLE. THE INTERPRETATION, CONSTRUCTION AND EFFECT OF THIS AGREEMENT SHALL BE GOVERNED BY THE LAWS OF TEXAS, AND TO THE MAXIMUM EXTENT ALLOWED BY LAW, IN ALL ARBITRATION PROCEEDINGS THE LAWS OF TEXAS SHALL BE APPLIED, WITHOUT REGARD TO ANY CONFLICTS OF LAWS PRINCIPLES. ALL STATUTES OF LIMITATION AND OF REPOSE THAT WOULD OTHERWISE BE APPLICABLE SHALL APPLY TO ANY ARBITRATION PROCEEDING. THE TRIBUNAL SHALL NOT HAVE THE AUTHORITY TO GRANT OR AWARD INDIRECT, CONSEQUENTIAL, PUNITIVE, EXEMPLARY OR SPECIAL DAMAGES.

ARTICLE 14. CONDITIONS PRECEDENT TO CLOSING

14.1 Conditions Precedent to Seller's Obligation to Close. Seller shall be obligated to consummate the sale of the Properties as contemplated by this Agreement on the Closing Date, provided the following conditions precedent have been satisfied or have been waived by Seller:

- 14.1.1 All representations and warranties of Buyer contained in this Agreement shall be true and correct in all material respects at and as of Closing as though such representations and warranties were made at and as of such time;
- 14.1.2 Buyer shall have complied in all material respects with all obligations and conditions contained in this Agreement to be performed or complied with by Buyer at or prior to the Closing; and
- 14.1.3 No suit, action or other proceedings shall be pending before any court or governmental entity in which it is sought by a person or entity (other than the parties hereto or any of their Affiliates, officers, directors, or employees) to restrain, enjoin or otherwise prohibit the consummation of the transactions contemplated by this Agreement, or to obtain substantial damages in connection with the transaction contemplated herein, nor shall there be any investigation by a governmental entity pending which might result in any such suit, action or other proceedings seeking to restrain, enjoin or otherwise prohibit the consummation of the transaction contemplated by this Agreement.

14.2 Conditions Precedent to Buyer's Obligation to Close. Buyer shall be obligated to consummate the purchase of the Properties as contemplated by this Agreement on the Closing Date, provided that the following conditions precedent have been satisfied or have been waived by Buyer:

- 14.2.1 All representations and warranties of Seller contained in this Agreement shall be true and correct in all material respects at and as of Closing as though such representations and warranties were made at and as of such time;

14.2.2 Seller shall have complied in all material respects with all obligations and conditions contained in this Agreement to be performed or complied with by Seller at or prior to the Closing; and

14.2.3 No suit, action or other proceedings shall be pending before any court or governmental entity in which it is sought by a person or entity (other than the parties hereto or any of their Affiliates, officers, directors, or employees) to restrain, enjoin or otherwise prohibit the consummation of the transactions contemplated by this Agreement, or to obtain substantial damages in connection with the transaction contemplated herein, nor shall there be any investigation by a governmental entity pending which might result in any such suit, action or other proceedings seeking to restrain, enjoin or otherwise prohibit the consummation of the transaction contemplated by this Agreement.

ARTICLE 15. TERMINATION

15.1 Grounds for Termination. This Agreement may be terminated at any time prior to Closing:

15.1.1 By the mutual written agreement of Seller and Buyer;

15.1.2 By Seller if Buyer fails or refuses to Close in breach of this Agreement or if the conditions precedent to Seller's obligation to Close are unmet at the time set for Closing;

15.1.3 By Buyer if Seller fails or refuses to Close in breach of this Agreement or if the conditions precedent to Buyer's obligation to Close are unmet at the time set forth Closing;

15.1.4 By Seller if the Purchase Price would be adjusted downward by twenty percent (20%) or more or by Buyer if the Purchase Price would be adjusted upward by twenty percent (20%) or more in accordance with the terms of this Agreement; or

15.1.5 By either party (provided the terminating party is not then in breach of any provisions of this Agreement), if Closing shall not have occurred within sixty (60) days following the originally scheduled Closing Date.

15.2 Effect of Termination.

15.2.1 Except as provided in Section 15.2.2 below, if this Agreement is terminated in accordance with Section 15.1, such termination shall be without liability of either party or any Affiliate, officer, director, or employee of such party, except for Seller's obligation (if applicable) to return the Earnest Money Deposit, as provided in

Article 3, the obligations to arbitrate any dispute arising from such termination and the obligations provided in Sections 15.3, 15.4, 15.5, and 17.3.

15.2.2 If this Agreement is terminated because of Buyer's failure or refusal to Close in breach of this Agreement or because the conditions precedent to Seller's obligation to Close provided in Section 14.1 are unmet at the time set for Closing, Seller shall be entitled to retain the Earnest Money Deposit as liquidated damages to reimburse Seller for its out-of-pocket fees and expenses incurred in connection with the transactions contemplated by this Agreement, unless any of the conditions precedent to Buyer's obligation to Close provided in Section 14.2 are also unmet at the time set for Closing. If this Agreement is terminated because of Seller's failure or refusal to Close in breach of this Agreement, any damages asserted by Buyer as a result of such failure or refusal to Close shall be limited to actual damages incurred by Buyer up to a maximum of \$1,500,000.

15.3 Dispute over Right to Terminate. If there is a dispute between the parties over either party's right to terminate this Agreement under Section 15.1, Closing shall not occur, as scheduled. The party which disputes the other party's right to terminate may initiate arbitration proceedings in accordance with Article 13 within thirty (30) Days after the date on which Closing was scheduled to occur and, if arbitration is so initiated, the dispute will be resolved through such arbitration proceeding. **If the party which disputes the termination right does not initiate an arbitration proceeding to resolve the dispute within the time period specified hereinabove, such party shall be deemed to have waived its right to object to such termination.**

15.4 Return of Documents. If this Agreement is terminated, each party shall return to the party which owns or is otherwise entitled thereto all books, records, maps, files, papers and other property in such party's possession (including copies of such materials and extracts therefrom) relating to the transaction contemplated by this Agreement.

15.5 Confidentiality. Notwithstanding the termination of this Agreement or any other provision of this Agreement to the contrary, the terms of the letter agreement executed by and among Seller, Anadarko Minerals, Inc. and Exploration Associates II, LLC dated October 8, 2002, shall remain in full force and effect.

ARTICLE 16. THE CLOSING

16.1 Preliminary Closing Statement. At least two (2) Days prior to the Closing Date, Seller shall provide Buyer with a preliminary Closing statement setting forth the adjusted Purchase Price and wiring instructions designating the account or accounts to which the adjusted Purchase Price is to be delivered in accordance with Section 16.3.2. Prior to the Closing Date, Buyer shall furnish Seller with Buyer's requested adjustments to such statement. Seller and Buyer shall attempt in good faith to resolve any differences between them, but if the parties are unable to agree, Seller's preliminary Closing statement shall be used for Closing.

16.2Obligations of Seller at Closing. At the Closing, Seller shall deliver to Buyer, unless waived by Buyer, the following:

16.2.1Documents substantially in the form of the Assignment and Bill of Sale attached hereto as ExhibitB, conveying all of Seller's right, title and interest in and to the Properties. The Assignment and Bill of Sale shall be executed and acknowledged in five (5)multiple originals or such greater number as agreed between the parties;

16.2.2Evidence that all consents and approvals prerequisite to the sale and conveyance of the Properties (except for consents and approvals of governmental entities customarily obtained subsequent to the transfer of title or with respect to Properties which have been withdrawn from the transaction in accordance with the terms hereof) have been obtained, as well as evidence of waiver or lapse of any unexercised preferential purchase rights applicable to the Properties;

16.2.3A Certificate substantially in the form of ExhibitC, executed by an authorized officer of Seller, certifying as to the matters specified in Section14.2.1;

16.2.4A Non-Foreign Affidavit substantially in the form of Exhibit D, executed by an authorized officer of Seller;

16.2.5Executed copies of mutually agreeable transfer orders or letters-in-lieu, government approved assignment forms and operator transfer forms to be prepared by Buyer; and

16.2.6Such other instruments as are necessary to carry out Seller's obligations under this Agreement.

16.3Obligations of Buyer at Closing. At the Closing, Buyer shall deliver to Seller, unless waived by Seller, the following:

16.3.1The Assignment and Bill of Sale referred to in Section 16.2.1, executed and properly acknowledged;

16.3.2The adjusted Purchase Price, less the Earnest Money Deposit, by wire transfer in accordance with Article3;

16.3.3A Certificate substantially in the form of ExhibitC, executed by an authorized representative of Buyer, certifying as to the matters specified in Section14.1.1.

16.3.4 Evidence of compliance with all governmental requirements for the posting of plugging or other applicable bonds relating to the ownership or operation of the Properties; and

16.3.5 Such other instruments as are necessary to carry out Buyer's obligations under this Agreement.

16.4 Site of Closing. Closing shall be held in Seller's offices in Houston, Texas or any other location mutually agreed in writing by Seller and Buyer.

ARTICLE 17. MISCELLANEOUS

17.1 Notices. All notices and other communications required, permitted or desired to be given hereunder must be in writing and sent by U.S. mail, properly addressed as shown below, and with all postage and other charges fully prepaid or by hand delivery or by facsimile transmission. Date of service by mail and hand delivery is the date on which such notice is received by the addressee and by facsimile is the date sent (as evidenced by fax machine confirmation of receipt), or if such date is not on a Business Day, then on the next date which is a Business Day. Each party may change its address by notifying the other party in writing.

If to Seller by mail or hand delivery:	Southwestern Energy Production Company 2350 N. Sam Houston Pkwy. E., Suite 300 Houston, Texas 77032 Attention: John Gargani
If to Seller by facsimile:	Southwestern Energy Production Company Number: 281-618-4862 Attention: John Gargani
If to Buyer by mail or hand delivery:	Dutch Petroleum, LLC 2110 Bank One Center 100 North Broadway Oklahoma City, Oklahoma 73102 Attention: William E. Dutcher
If to Buyer by facsimile:	Dutch Petroleum, LLC Number: 405-235-7150 Attention: William E. Dutcher

17.2 Conveyance Costs. Buyer shall be solely responsible for filing and recording documents related to the transfer of the Properties from Seller to Buyer and for all costs and fees associated therewith, including filing the assignment of the Properties with appropriate federal, state and local authorities as required by applicable Law. Promptly following Buyer's receipt of

the recorded documents, Buyer shall furnish Seller with all recording data and evidence of all required filings.

17.3 Brokers' Fees. Neither party has retained any brokers, agents or finders in connection with this transaction that would result in any liability on the other party for any fees or commission. **Each party agrees to release, protect, indemnify, defend and hold the other harmless from and against any and all Claims with respect to any commissions, finders' fees or other remuneration due to any broker, agent or finder claiming by, through or under such party.**

17.4 Further Assurances. From and after Closing, at the request of Seller but without further consideration, Buyer will execute and deliver or use reasonable efforts to cause to be executed and delivered such other instruments of conveyance and take such other actions as Seller reasonably may request to more effectively put Seller in possession of any property which was not intended by the parties to be conveyed by Buyer. From and after Closing, at the request of Buyer but without further consideration, Seller shall execute and deliver or use reasonable efforts to cause to be executed and delivered such other instruments of conveyance and take such other actions as Buyer reasonably may request to more effectively put Buyer in possession of the Properties. If any of the Properties are incorrectly described, the description shall be corrected upon proof of the proper description.

17.5 Survival of Representations and Warranties. Unless otherwise expressly limited herein, all representations, warranties, indemnities, covenants and agreements contained in this Agreement, to the extent not fully performed or waived prior to Closing, shall survive the Closing indefinitely. The parties have made no representations or warranties except those expressly set forth in this Agreement.

17.6 Amendments and Severability. No amendments or other changes to this Agreement shall be effective or binding on either of the parties unless the same shall be in writing and signed by both Seller and Buyer. The invalidity of any one or more provisions of this Agreement shall not affect the validity of this Agreement as a whole, and in case of any such invalidity, this Agreement shall be construed as if the invalid provision had not been included herein.

17.7 Successors and Assigns. This Agreement shall not be assigned, either in whole or in part, without the prior express written consent of the non-assigning party. Assignment of this Agreement by either party shall not relieve the assigning party of liability hereunder in the event of non-performance or breach of this Agreement by such party's assignee. The terms, covenants and conditions contained in this Agreement shall be binding upon and shall inure to the benefit of Seller and Buyer and their respective successors and assigns, and such terms, covenants and conditions shall be covenants running with the land and with each subsequent transfer or assignment of the Properties.

17.8 Headings. The titles and headings set forth in this Agreement have been included solely for ease of reference and shall not be considered in the interpretation or construction of this Agreement.

17.9 Governing Law. This Agreement shall be governed by and construed under the Laws of the State of Texas, excluding any choice of law rules which may direct the application of the Laws of another jurisdiction. This provision survives termination of this Agreement.

17.10 No Partnership Created. It is not the purpose or intention of this Agreement to create (and it shall not be construed as creating) a joint venture, partnership or any type of association, and the parties are not authorized to act as agent or principal for each other with respect to any matter related hereto.

17.11 Public Announcements. Neither the Seller Group nor the Buyer Group (as defined in Article 8) shall issue a public statement or press release with respect to the transaction contemplated herein (including the price and other terms) without the prior written consent of the other party, except as required by Law or listing agreement with a national security exchange and then only after prior consultation with the other party.

17.12 No Third Party Beneficiaries. Nothing contained in this Agreement shall entitle anyone other than Seller or Buyer or their authorized successors and assigns to any claim, cause of action, remedy or right of any kind whatsoever.

17.13 Deceptive Trade Practices. As partial consideration for the parties agreeing to enter into this Agreement, the parties each can and do expressly waive the provisions of all consumer protection Laws of the State of Texas, or any other state, applicable to this transaction that may be waived by the parties; it is not the intent of the parties to waive and the parties shall not waive any applicable Law or provision thereof which is prohibited by Law from being waived. Each party represents to the other that such party has had an adequate opportunity to review the preceding waiver provision, including the opportunity to submit the same to legal counsel for review and comment, and understands the rights being waived herein.

17.14 Tax Deferred Exchange Election. Either party may elect to structure the conveyance of the Properties as part of an exchange under Article 1031 of the Internal Revenue Code of 1986, as amended. The parties agree to execute all documents, conveyances or other instruments necessary to effectuate an exchange. The party requesting that the transaction be structured as a tax free exchange shall be responsible for all additional costs associated with so structuring the transaction.

17.15 Not to be Construed Against Drafter. The parties acknowledge that they have had an adequate opportunity to review each and every provision contained in this

Agreement and to submit the same to legal counsel for review and comment, including expressly but without limitation the waivers and indemnities in Articles 4, 6, 8, 9, and 17. Based on said review and consultation, the parties agree with each and every term contained in this Agreement. Based on the foregoing, the parties agree that the rule of construction that a contract be construed against the drafter, if any, shall not be applied in the interpretation and construction of this Agreement.

17.16 Entire Agreement. This Agreement supersedes all prior negotiations, understandings, letters of intent and agreements (whether oral or written) and any contemporaneous oral agreements between the parties relating to the Properties and constitutes the entire understanding and agreement between the parties with respect to the sale and purchase of the Properties.

17.17 **Conspicuousness of Provisions.** The parties acknowledge that the provisions contained in this Agreement that are set out in “bold” satisfy the requirement of the express negligence rule and any other requirement at law or in equity that provisions contained in a contract be conspicuously marked or highlighted.

17.18 Execution in Counterparts. This Agreement may be executed in counterparts, which shall when taken together constitute one valid and binding agreement. Execution of this Agreement via facsimile shall be effective, and signatures received via facsimile shall be binding upon the parties hereto and shall be effective as originals.

The parties have executed this Agreement on the day and year first set forth above.

SOUTHWESTERN ENERGY PRODUCTION

COMPANY

By:/s/ Richard F. Lane

Richard F. Lane
Executive Vice President

DUTCH PETROLEUM, LLC

By:/s/ Mack R. Ames

Name: Mack R. Ames

Title: Vice President

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LIST OF SUBSIDIARIES

Subsidiary Name

Arkansas Western Gas Company

**State of Incorporation or
Organization**

Arkansas

SEECO, Inc.
Southwestern Energy Production Company
Diamond "M" Production Company
Southwestern Energy Services Company
Southwestern Energy Pipeline Company
A.W. Realty Company
Overton Partners, L.P.

Arkansas
Arkansas
Delaware
Arkansas
Arkansas
Arkansas
Texas

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on FormS-8 (File Nos. 333-03787, 333-03789, 333-64961, 333-96161, 333-42484, 333-69720, 333-100702 and 333-101160) and FormS-3 (File No. 333-101658) of Southwestern Energy Company, of our report dated February5, 2003 relating to the financial statements of Southwestern Energy Company, which appears in this Annual Report on Form10-K.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February14, 2003

Exhibit23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers, we hereby consent to the reference in this Form10-K of Southwestern Energy Company to our Firm's name and our Firm's review of the proved oil and gas quantities reserve quantities as of December 31, 2002, and to the incorporation by reference of our Firm's name and review into Southwestern Energy Company's previously filed Registration Statements on FormS-8 (File Nos. 333-03787, 333-03789, 333-64961, 333-96161, 333-42484, 333-69720, 333-100702 and 333-101160) and FormS-3 (File No.333-101658).

NETHERLAND, SEWELL ASSOCIATES, INC.

By /s/ J. Carter Henson, Jr.
Name: J. Carter Henson, Jr.
Title: Senior Vice President

Houston, Texas
February14, 2003

Exhibit23.3

CONSENT OF KA ENERGY CONSULTANTS, INC.

We hereby consent to the reference in this Form10-K of Southwestern Energy Company to our Firm's name and our Firm's review of the proved oil and gas quantities reserve quantities as of December31, 2002, and to the incorporation by reference of our Firm's name and review into Southwestern Energy Company's previously filed Registration Statements on FormS-8 (File Nos. 333-03787, 333-03789, 333-64961, 333-96161, 333-42484, 333-69720, 333-100702 and 333-101160) and FormS-3 (File No.333-101658).

KA ENERGY CONSULTANTS, INC.

By /s/ Jim F. Stinson

Name: Jim F. Stinson

Title: Vice President

Tulsa, Oklahoma
February 14, 2003

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