SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

(Mark one)

[x] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 (Fee required)

For the fiscal year ended December 31, 1995

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 (No fee required)

For the transition period from ______________ to ______________

Commission file number 1-8246

SOUTHWESTERN ENERGY COMPANY

(Exact name of registrant as specified in charter)

ARKANSAS	71-0205415
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1083 Sain Street, Fayetteville, Arkansas	72703
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (501) 521-1141

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 $.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 X 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._____

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $287,525,532 based on the New York Stock Exchange - Composite Transactions closing price on March 25, 1996 of $11.75.

The number of shares outstanding as of March 25, 1996, of the Registrant's Common Stock, par value $.10, was 24,701,349.

DOCUMENTS INCORPORATED BY REFERENCE

Documents incorporated by reference and the Part of the Form 10-K into which the document is incorporated: (1) Annual Report to holders of the Registrant's Common Stock for fiscal year ended December 31, 1995 - PARTS I, II, and IV; and (2) definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 13, 1996 - PART III.

SOUTHWESTERN ENERGY COMPANY
FORM 10-K
ANNUAL REPORT
For the Year Ended December 31, 1995

TABLE OF CONTENTS

PART I

Item 1. BUSINESS

Southwestern Energy Company (the Company) is a diversified natural gas company. Through its wholly-owned subsidiaries, the Company is engaged in gas and oil exploration and production, natural gas gathering and transmission as well as natural gas distribution. The principal sites for the Company's exploration and production program are the Arkoma Basin of Arkansas, the Gulf Coast (both onshore and shallow waters offshore) and the Anadarko Basin of Oklahoma. The Company's natural gas gathering transmission and distribution properties are located in Arkansas and Missouri. The Company was incorporated under the laws of the state of Arkansas and is an exempt holding company under the Public Utility Holding Company Act of 1935.

The Company was organized in 1929 as a local distribution company in northwest Arkansas. In 1943, the Company commenced a program of exploration for and development of natural gas reserves in Arkansas for supply to its utility customers. In 1971, the Company initiated an exploration and development program outside Arkansas, unrelated to the utility requirements. Since that time, the Company's exploration and development activities outside Arkansas have expanded. The exploration, development, and production activities are a separate, primary business of the Company.

Exploration and production activities consist of ownership of mineral interests in productive and undeveloped leases located entirely within the United States. The Company engages in gas and oil exploration and production through its subsidiaries, SEECO, Inc. (SEECO) and Southwestern Energy Production Company (SEPCO). SEECO operates exclusively in the state of Arkansas and holds a large base of both developed and undeveloped gas reserves and conducts an ongoing drilling program in the historically productive Arkansas section of the Arkoma Basin. SEPCO conducts an exploration program in areas outside Arkansas, including the Gulf Coast areas of Louisiana and Texas, the Anadarko Basin of Oklahoma, and the Delaware Basin of New Mexico. SEPCO also holds a block of leasehold acreage located on the Fort Chaffee military reservation in western Arkansas and in other parts of Arkansas away from the operating areas of the Company's other subsidiaries.

The Company's subsidiary Arkansas Western Gas Company (Arkansas Western) operates integrated natural gas distribution systems in Arkansas and Missouri serving approximately 168,000 customers. Arkansas Western is the largest single purchaser of SEECO's gas production. Southwestern Energy Pipeline Company (SWPL) owns a 47.93% general partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK), a 258 mile long intrastate natural gas transmission system that extends across northern Arkansas. SWPL also serves as operator of the pipeline.

This document may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. See "Management's Discussion and Analysis of Financial Condition and Results of Operation" in Part II, Item 7 of this Report for a discussion of important factors that could affect the validity of any such forward-looking statements. A discussion of the primary businesses conducted by the Company through its wholly-owned subsidiaries follows.

NATURAL GAS AND OIL EXPLORATION AND PRODUCTION

Substantially all of the Company's exploration and production activities and reserves are concentrated in Arkansas, the Gulf Coast areas of Louisiana and Texas, Oklahoma, and New Mexico. At December 31, 1995, the Company had proved natural gas reserves of 294.9 billion cubic feet (Bcf) and proved oil reserves of 2,152 thousand barrels (MBbls). Revenues of the exploration and production subsidiaries are predominately generated from production of natural gas. The Company's gas production was 34.5 Bcf in 1995, down 8% from 37.7 Bcf in 1994. Sales of gas production accounted for 93% of total operating revenues for this segment in 1995, 96% in 1994, and 98% in 1993. SEECO's largest customer for sales of its gas production was the Company's utility subsidiary. However, sales to unaffiliated purchasers, as a percentage of total sales made by both SEECO and SEPCO, have generally increased during the last three years as compared to periods prior to 1993. This increased percentage is due primarily to higher production from Arkansas properties, from producing property acquisitions, and from properties developed in the Gulf Coast areas. Sales to unaffiliated purchasers accounted for 60% of total gas volumes sold by the exploration and production segment in 1995, 63% in 1994, and 64% in 1993.

Gas volumes sold by SEECO to Arkansas Western for its northwest Arkansas division (AWG) were 8.5 Bcf in 1995, 8.8 Bcf in 1994, and 7.1 Bcf in 1993. Through these sales, SEECO furnished 65% of the northwest Arkansas system's requirements in 1995, 64% in 1994, and 57% in 1993. The increase in 1994 compared to 1993 was due largely to increased storage injections and higher volumes resulting from a settlement reached to resolve certain gas cost issues before the Arkansas Public Service Commission (APSC). The settlement, which involved the price of gas sold under a long-term contract between SEECO and AWG, is hereafter referred to as the "Gas Cost Settlement", and is discussed more fully below. SEECO also delivered approximately 1.4 Bcf in 1995, 1.5 Bcf in 1994, and 2.2 Bcf in 1993 directly to certain large business customers of AWG through a transportation service of the utility subsidiary that became effective in October, 1991. Most of the sales to AWG are pursuant to a twenty-year contract between SEECO and AWG entered into in July, 1978, under which the price had been frozen since 1984. This contract was amended in 1994 as a result of the Gas Cost Settlement that became effective July 1, 1994, and calls for sales under the contract to take place at a price which is equal to a spot market index plus a premium. The Gas Cost Settlement has resulted in a lower contract price based on market conditions since the settlement. That effect has been offset in part by provisions of the Gas Cost Settlement which allow additional volumes to be sold under the amended contract. The amended contract provides for volumes equal to the historical level of sales under the contract to be sold at the spot market index plus a premium of $.95 per Mcf, while incremental sales volumes receive a premium of $.50 per Mcf. In 1995, 7.7 Bcf (net to the Company's interest) was sold under the contract, compared to 8.1 Bcf in 1994 and 6.0 Bcf in 1993. Other significant terms of the Gas Cost Settlement preclude the parties thereto from asking for refunds, transfer certain of AWG's natural gas storage facilities to SEECO, and prohibited AWG from filing an application for a rate increase before January, 1996. In addition to this contract, SEECO also sells gas to AWG under newer long-term contracts with flexible pricing provisions and under short-term spot market arrangements. SEECO's sales to AWG have accounted for approximately 31% of total exploration and production revenues each of the last three years.

SEECO's sales to Associated Natural Gas Company (Associated), a division of Arkansas Western which operates natural gas distribution systems in northeast Arkansas and parts of Missouri, were 5.4 Bcf in 1995, 5.1 Bcf in 1994, and 5.7 Bcf in 1993. These deliveries accounted for approximately 59% of Associated's total requirements in 1995, 58% in 1994, and 67% in 1993. These sales represented 16% of total exploration and production revenues in 1995, 14% in 1994, and 15% in 1993. Deliveries to Associated increased in 1995 due to colder weather in the heating season and decreased in 1994 due to warmer weather. Effective October, 1990, SEECO entered into a ten-year contract with Associated to supply its base load system requirements at a price to be redetermined annually. Deliveries under this contract were made at a price of $1.90 per thousand cubic feet (Mcf) from inception of the contract through the first nine months of 1993, increased to $2.385 per Mcf for the contract period ended September 30, 1994, decreased to $2.20 per Mcf for the contract period ended September 30, 1995, and are currently being made at a price of $1.785 per Mcf.

In 1990, SEECO completed the initial mapping and engineering phases of a multi-year geological field study of the Arkoma Basin of Arkansas. The product developed was an extensive database and geologic interpretations of the distribution of gas-bearing sands in the region and resulted in the identification of 69.7 Bcf of proved undeveloped reserves that were added to the Company's base of proved reserves. At December 31, 1995, after transfers and revisions, the remaining proved undeveloped reserves identified by the study were 40.1 Bcf. The data base developed is periodically updated by drilling activity and provides guidance in the Company's development drilling program. The development drilling program added 17.1 Bcf in 1995, 22.2 Bcf in 1994, and 27.0 Bcf in 1993 of new natural gas reserve additions and resulted in the transfer of .7 Bcf in 1995, 3.0 Bcf in 1994, and 2.6 Bcf in 1993 from the proved undeveloped category to the proved developed category. SEECO participated in a total of 80 development wells during 1995 with a completion rate of 68%. SEECO's sales to unaffiliated purchasers were 10.3 Bcf in 1995, 10.7 Bcf in 1994, and 10.0 Bcf in 1993. At present, SEECO's contracts for sales of gas to unaffiliated customers consist of short-term sales made to customers of AWG's transportation program and spot sales into markets away from AWG's distribution system. These sales are subject to seasonal price swings. In the past, the Company's ability to enter into sales arrangements with unaffiliated customers has generally been constrained by a lack of pipeline transportation to markets away from the Arkoma Basin. Initiatives of the FERC to restructure the natural gas interstate pipeline service rules through its Order No. 636 series have improved and should continue to improve the Company's ability to market its existing and potential reserves. Also contributing to the increase in the ability of SEECO to market its gas to unaffiliated customers was the completion of NOARK in September, 1992, as explained more fully below under "Natural gas gathering, transmission and distribution." SEECO's sales to unaffiliated purchasers have accounted for approximately 22% of total exploration and production revenues for the last three years.

At December 31, 1995, the gas and oil reserves of SEPCO were located primarily in Oklahoma and the Gulf Coast areas of Louisiana and Texas. SEPCO also owns gas reserves in Arkansas, primarily related to its properties on the Fort Chaffee military reservation. SEPCO holds about 27% of the Company's natural gas reserves and all of its oil reserves. SEPCO's gas sales were 10.3 Bcf in 1995, down from 13.1 Bcf in 1994 and 12.9 Bcf in 1993. The decrease in 1995 was primarily due to declining production in the Company's offshore Gulf of Mexico properties. SEPCO's production is sold under contracts which reflect current short-term prices and which are subject to seasonal price swings.

Oil production was 229 MBbls in 1995, compared to 200 MBbls in 1994 and 97 MBbls in 1993. The increase in oil production in 1995 and 1994 primarily resulted from acquisitions of producing properties during those years. The Company's exploration program has been directed almost exclusively toward natural gas in recent years. The Company plans to continue to concentrate on developing gas reserves, but will also selectively seek opportunities to participate in projects oriented toward oil production. Over the long-term, however, oil sales are not expected to account for a significant part of the Company's future revenues. SEPCO's gas and oil sales accounted for 31% of total exploration and production operating revenues in 1995 and 33% in both 1994 and 1993.

In 1989, SEPCO purchased at oral auction 11,000 undrilled acres containing 17 separate drilling units on the Fort Chaffee military reservation of western Arkansas. The total cost of this acreage was approximately $11.0 million. To date, the Company has drilled or participated in nine wells at Fort Chaffee that have discovered an estimated 47.1 Bcf of new gas reserves, net to the Company's interest. Sales of gas production from Fort Chaffee totaled 3.0 Bcf in 1995, 4.3 Bcf in 1994, and 5.1 Bcf in 1993. The decrease is a result of the natural decline in the productive capability of these properties. Conflicts with military training activities have limited SEPCO's drilling operations at Fort Chaffee. The Company has attempted to work with the military to improve work schedules and operating restrictions, but those efforts have been to little avail. Fort Chaffee has been closed as an active military base, but is presently planned to be a training facility for the National Guard and other governmental agencies. The Company is not able to predict whether this change in activities conducted at Fort Chaffee will result in less restrictive operating conditions. As a result, Fort Chaffee will play a lesser role in the Company's plans.

Outside Arkansas, the Company added 18.0 Bcf of new reserves in 1995 and
8.7 Bcf in 1994 from drilling. Of that total, 11.3 Bcf in 1995 and 8.5 Bcf in 1994 were from discoveries in the coastal areas of Texas and Louisiana. The Gulf Coast region continues to be the primary focus of most of the Company's exploration activity. The Company currently is participating in several 3-D seismic programs in south Louisiana and spent approximately $5.0 million in 1995 on the largest of these programs, a 130 square mile 3-D seismic data acquisition joint venture in the east Atchafalaya Basin of south Louisiana, primarily in St. Martin Parish. The Company has a 50% working interest in the venture. About 100,000 acres is under option, convertible to leasehold acreage as the seismic data is interpreted. While the options carry rights to all depths, the Company's interest is primarily in those objectives deeper than the historically productive zones. The Company expects this venture to generate a significant number of well-defined exploration prospects. Drilling will not commence any earlier than the fourth quarter of 1996. The Company is also participating in a development drilling program in the Delaware Basin of New Mexico, keyed off three 1995 discovery wells. The Company will participate with up to a 50% working interest in 10 or more development wells during 1996 and more in 1997. The Company also has two more exploratory wells to drill in the area.

During 1995 and 1994, the Company increased its emphasis on acquisitions of producing properties and expects that effort to continue as a supplement to its exploration and development drilling programs. The Company acquired approximately 4.5 Bcf of gas and 851 MBbls of oil during 1995, and 20.6 Bcf of gas and 1,038 MBbls of oil during 1994. The 1995 acquisitions were primarily in the Gulf Coast areas of Louisiana and Texas and the 1994 acquisitions were primarily in the Anadarko Basin of Oklahoma.

In the natural gas and oil exploration segment, competition is encountered primarily in obtaining leaseholds for future exploration. Competition in the state of Arkansas has increased in recent years, due largely to the development of improved access to interstate pipelines. Due to the Company's significant leasehold acreage position in Arkansas and its long-time presence and reputation in this area, the Company believes it will continue to be successful in acquiring new leases in Arkansas. While improved intrastate and interstate pipeline transportation in Arkansas should increase the Company's access to markets for its gas production, these markets will generally be served by a number of other suppliers. Thus, the Company will encounter competition which may affect both the price it receives and contract terms it must offer. Outside Arkansas, the Company is less well-established and faces competition from a larger number of other producers. The Company has in recent years been successful in building its inventory of undeveloped leases and obtaining participating interests in drilling prospects outside Arkansas.

The Company expects its 1996 capital expenditures for gas and oil exploration and development to total $71.0 million, down from $82.2 million incurred in 1995. Expenditures in 1996 for this segment are expected to be $24.5 million for development drilling, including $14.5 million for the Company's Arkansas program, $20.0 million for producing property acquisitions, and a total of $12.4 million for exploratory drilling and seismic. Most of the Company's risk-oriented spending will be directed toward its 3-D seismic joint ventures. The Company will review this budget periodically during the year for possible adjustment depending upon cash flow projections related to fluctuating prices for natural gas and oil.

NATURAL GAS GATHERING, TRANSMISSION AND DISTRIBUTION

The Company's natural gas distribution operations are concentrated primarily in north Arkansas and southeast Missouri. The Company serves approximately 168,000 retail customers and obtains a substantial portion of the gas they consume through its Arkoma Basin gathering facilities. The Company is also a participant in a partnership that owns the NOARK Pipeline System. The complexity of AWG's distribution operations, particularly its gathering system in the Arkoma Basin gas fields, increased significantly with the start up of NOARK. AWG provides field management services to NOARK under a contract with the partnership and AWG's gathering system delivers to NOARK a substantial part of the gas NOARK transports. The Company completed a pipeline in 1993 that connects NOARK to Associated's distribution system, tying together the Company's two primary gas distribution systems.

Arkansas Western consists of two operating divisions. The AWG division gathers natural gas in the Arkansas River Valley of western Arkansas and transports the gas through its own transmission and distribution systems, ultimately delivering it at retail to approximately 101,000 customers in northwest Arkansas. The Associated division currently receives its gas from transportation pipelines and delivers the gas through its own transmission and distribution systems, ultimately delivering it at retail to approximately 67,000 customers primarily in northeast Arkansas and southeast Missouri. Associated, formerly a wholly owned subsidiary of Arkansas Power and Light Company, was acquired and merged into Arkansas Western effective June 1, 1988. The Arkansas Public Service Commission (APSC) and the Missouri Public Service Commission (Missouri Commission) regulate the Company's utility rates and operations. In Arkansas, the Company operates through municipal franchises which are perpetual by state law. These franchises, however, are not exclusive within a geographic area. In Missouri, the Company operates through municipal franchises with various terms of existence.

AWG and Associated deliver natural gas to residential, commercial, and industrial customers. The industrial customers are generally smaller concerns using gas for plant heating or product processing. AWG has no restriction on adding new residential or commercial customers and will supply new industrial customers which are compatible with the scale of its facilities. AWG has never denied service to new customers within its service area or experienced curtailments because of supply constraints. Associated has not denied service to new customers within its service area or experienced curtailments because of supply constraints since the acquisition date. Curtailment of large industrial customers of AWG and Associated occurs only infrequently when extremely cold weather requires that systems be dedicated exclusively to human needs customers.

AWG and Associated have experienced a general trend in recent years toward lower rates of usage among their customers, largely as a result of conservation efforts which the Company encourages. Competition is increasingly being experienced from alternative fuels, primarily electricity, fuel oil, and propane. A significant amount of fuel switching has not been experienced, though, as natural gas is generally the least expensive, most readily available fuel in the service territories of AWG and Associated.

The competition from alternative fuels and, in a limited number of cases, alternative sources of natural gas has intensified in recent years as a result of the significant declines in prices of petroleum products and the deliverability surplus of natural gas experienced in the past. Industrial customers are most likely to consider utilization of these alternatives, as they are less readily available to commercial and residential customers. In an effort to provide some pricing alternatives to its large industrial customers with relatively stable loads, AWG offers an optional tariff to its larger business customers and to any other large business customer which shows that it has an alternate source of fuel at a lower price or that one of its direct competitors in another area has access to cheaper sources of energy. This optional tariff enables those customers willing to accept the risk of price and supply volatility to direct AWG to obtain a certain percentage of their gas requirements in the spot market. Participating customers continue to pay the nongas cost of service included in AWG's present tariff for large business customers and agree to reimburse AWG for any take-or-pay liability caused by spot market purchases on the customer's behalf. In an effort to more fully meet the service needs of larger business customers, both AWG and Associated instituted a transportation service in October, 1991, that allows such customers in Arkansas to obtain their own gas supplies directly from other suppliers. Associated has offered transportation service to its larger customers in Missouri for several years and AWG's spot market purchasing program has provided customers in northwest Arkansas with many of the benefits of transportation service. Under the programs, transportation service is available in Arkansas to any large business customer which consumes a minimum of 150,000 Mcf per year and no less than 3,000 Mcf per month. Transportation service is available in Missouri to any customer whose average monthly usage exceeds 2,000 Mcf. The minimums can be met by aggregating facilities under common ownership. A total of eleven customers are currently using the Arkansas transportation service, including three of AWG's four largest customers in northwest Arkansas and Associated's two largest customers in northeast Arkansas. Associated's 13 largest Missouri customers are currently using transportation service.

AWG purchases its system gas supply directly at the wellhead under long-term contracts. Purchases are made from approximately 290 working interest owners in 484 producing wells. As previously indicated, SEECO furnished approximately 65% of AWG's system requirements in 1995, 64% in 1994, and 57% in 1993. A significant portion of AWG's unaffiliated supply comes from market responsive, long-term contracts which take advantage of the lower prices that have generally been available from gas suppliers.

At December 31, 1995, AWG had a gas supply available to its northwest Arkansas system of approximately 213 Bcf of proved developed reserves, equal to 15 times current annual usage. Of this total, approximately 109 Bcf were net reserves available from SEECO. Under the terms of the Gas Cost Settlement, SEECO's reserves are no longer dedicated to AWG. However, a portion of these reserves are utilized to meet the annual sales volume commitment of 9.0 Bcf
(gross) under the amended long-term contract with AWG. For purposes of determining AWG's available gas supply, deliveries to AWG's spot market purchasing program or transportation customers and the reserves related to those deliveries are not considered.

Associated purchases gas for its system supply from unaffiliated suppliers accessed by interstate pipelines and from SEECO. Purchases from SEECO are under a ten-year contract with annual price redeterminations. Purchases from unaffiliated suppliers are under firm contracts with terms between one and three years. The rates charged by these suppliers include demand components to ensure availability of gas supply, administrative fees, and a commodity component which is based on spot market gas prices. Associated's gas purchases are transported through eight pipelines. The pipeline transportation rates include demand charges to reserve pipeline capacity and commodity charges based on volumes transported. Associated has also contracted with five of the interstate pipelines for storage capacity to meet its peak seasonal demands. 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. In 1993, Associated renegotiated its purchase contracts with interstate pipelines in accordance with the pipeline restructuring as mandated by the Federal Energy Regulatory Commission's (FERC) Order No. 636. Prior to Order 636, Associated purchased its system supply from six interstate pipelines, SEECO, and various spot market suppliers.

Over the past several years changes at the federal level have brought significant changes to the regulatory structure governing interstate sales and transportation of natural gas. The FERC's Order No. 636 series changed a major portion of the gas acquisition merchant function provided to gas distributors by interstate pipelines. AWG already obtains its supply at the wellhead directly from producers and has not been directly impacted by Order No. 636. Associated has acquired the bulk of its gas supply at the wellhead since its acquisition by Arkansas Western, but continued until Order No. 636 to purchase a portion of both its peak and base requirements from interstate suppliers. The changes mandated by Order No. 636 have placed the responsibility for arranging firm supplies of natural gas directly on local distribution companies and have, as a result, lessened the ability of Associated to purchase gas on the short-term spot market

As a result of pipeline deregulation, Associated has paid, net of refunds received, approximately $2.6 million in contract reformation costs and take-or-pay costs, and $2.5 million in transition costs which its interstate pipeline suppliers incurred and were allowed to recover. The Company anticipates full recovery of the $2.5 million in transition costs incurred. To date, the Company has recovered approximately $1.5 million of the contract reformation costs and take-or-pay costs from its utility sales customers in the state of Missouri. Of the unrecovered $1.1 million related to contract reformation costs and take-or-pay costs, $.5 million is applicable to Associated's transportation customers in the state of Missouri and $.6 million is applicable to all customers in the state of Arkansas. As discussed below, the Missouri Commission has disallowed recovery of the $.5 million from Associated's Missouri transportation customers.

AWG also purchases gas from unaffiliated producers under take-or-pay contracts. Currently, the Company believes that it does not have a significant exposure to liabilities resulting from these contracts, although the Company's exposure to take-or-pay liabilities to its gas suppliers has increased in recent years as a result of a decline in its gas purchase requirements. This decline occurred because some of its large business customers converted to the transportation service offered by AWG and began to obtain their own gas supplies directly from other sources. The Company expects to be able to continue to satisfactorily manage its exposure to take-or-pay liabilities.

As discussed earlier, Associated purchases a portion of its gas supply at the wellhead from one of the Company's gas producing subsidiaries under a long-term firm contract entered into in October, 1990. On July 14, 1995, Associated received an order from the Missouri Commission disallowing the recovery of approximately $2.0 million of gas costs. The order was the result of gas cost audits covering the five-year period ending August 31, 1993. Of the total disallowed, $1.5 million represented a portion of the difference between the price paid by Associated under its long-term firm contract with SEECO and a spot market index price for gas delivered into an interstate pipeline operating in the Arkoma Basin. The balance of $.5 million disallowed represented take-or-pay charges passed through to Associated by its interstate suppliers and allocable to transportation customers of Associated, as discussed above. The APSC had previously reviewed the costs charged to Arkansas ratepayers under this contract and found them to be proper and allowable for recovery. Associated has appealed the Missouri Commission's decision to the Circuit Court of Cole County, Missouri and that court has stayed the Missouri Commission's order and has directed Associated to pay the money to be refunded under the Missouri Commission's order into the registry of the court while the appeal is pending. The Staff of the Missouri Commission has also recommended the disallowance of an additional $.7 million of gas costs as a result of an audit for the year ended August, 1994. The Missouri Commission has not yet issued an order in connection with that recommendation. The Company will continue to defend its pricing policies and seek recovery of these costs from Associated's customers. The Company does not expect the ultimate outcome of these matters to have a material impact on the results of operations or the financial position of the Company.

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 in recent years as the structure of the Company's utility rates has become somewhat flatter; i.e., most recovery of return on rate base is built into a customer charge and the first step of its rates.

Gas distribution revenues in future years will be impacted by both customer growth and rate increases allowed by regulatory commissions. In recent years, AWG has experienced customer growth of approximately 3.5% to 4.0% annually, while Associated has experienced customer growth of approximately

1% annually. Based on current economic conditions in the Company's service territories, the Company expects this trend in customer growth to continue. AWG and Associated pass along to customers through an automatic cost of gas adjustment clause any increase or decrease experienced in purchased gas costs. As previously mentioned, the APSC and the Missouri Commission regulate the Company's utility rates and operations. AWG filed an application with the APSC on January 30, 1996, for a rate increase of $7.2 million annually. The APSC has ten months in which to reach a decision on the amount of the rate increase to be approved. As a result, any increase granted will likely not become effective until late 1996. The Company anticipates filing a rate increase request for Associated's operations in late 1996. Rate increase requests which may be filed in the future will depend on customer growth, increases in operating expenses, and additional investments in property, plant and equipment. AWG's rates for gas delivered to its retail customers are not regulated by the FERC, but its transmission and gathering pipeline systems are subject to the FERC's regulations concerning open access transportation since AWG accepted a blanket transportation certificate in connection with its merger with Associated.

NOARK is an intrastate pipeline constructed by a limited partnership in which SWPL holds a 47.93% general partnership interest and is the pipeline's operator. NOARK's main line was completed and placed in service in September, 1992. A lateral line of NOARK that allows the Company's gas distribution segment to augment its supply to an existing market as well as supply gas to new markets was completed and placed in service in November, 1992. The 258 mile long pipeline originates near the Fort Chaffee military reservation in western Arkansas and terminates in northeast Arkansas. NOARK interconnects with three major interstate pipelines and provides additional access to markets for gas production of both the Company and other producers. Construction of an eight-mile interstate pipeline connecting NOARK to the distribution system of Associated was completed during 1993. NOARK is a public utility regulated by the APSC. The APSC established NOARK's maximum transportation rate based on its original construction cost estimate of approximately $73.0 million. Due to construction problems and the addition of a compressor station, the ultimate costs of the pipeline exceeded the original estimate by approximately $30 million. NOARK has a capacity of approximately 141 MMcfd. In 1995, NOARK had an average daily throughput of 86 MMcfd, compared to 82 MMcfd in 1994, and 79 MMcfd in 1993. Arkansas Western has contracted for 41 MMcfd of firm capacity on NOARK under a transportation contract with an original term of ten years. The remaining term of that contract is seven years and the contract is renewable year to year until terminated by 180 days notice. NOARK also had a five-year transportation contract with an independent marketer to transport 50 MMcfd through NOARK on a firm basis. The Company's exploration and production segment was supplying 25 MMcfd of the volumes transported by the marketer under that agreement. In late 1993, the gas marketing company filed suit against NOARK, the Company, and certain of its affiliates, and, effective January 1, 1994, ceased transporting gas under its agreement with NOARK. In late 1995, the suit was settled prior to trial. In exchange for a $6.0 million payment to NOARK, the marketer was released from its obligations under its firm transportation agreement and its contract with the Company's affiliates. The Company is currently making its own sales arrangements and transporting production through NOARK which was previously purchased by the marketer.

NOARK has been operating below capacity and generating losses since it was placed in service. The Company expects further losses from its equity investment in NOARK until the pipeline is able to increase its level of throughput and until improvement occurs in the competitive conditions which determine the transportation rates NOARK can charge. NOARK provides additional pipeline capacity to a portion of the Arkoma Basin in Arkansas which was not previously adequately served by pipelines offering firm transportation. NOARK competes primarily with two interstate pipelines in its gathering area. One of those elected to become an open access transporter subsequent to NOARK's start of construction. The increased availability of interruptible transportation service has intensified the competitive environment within which

NOARK operates. The Company and the other partners of NOARK are currently investigating several options which would improve NOARK's future financial prospects.

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 noncapital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. The Company has no material amounts accrued at December 31, 1995. Additionally, management believes any future remediation or other compliance related costs will not have any material effect upon capital expenditures, earnings, or the competitive position of the Company's subsidiaries.

REAL ESTATE DEVELOPMENT

A. W. Realty Company (AWR) owns an interest in approximately 170 acres of real estate, most of which is undeveloped. AWR's real estate development activities are concentrated on a 130-acre tract of land located near the Company's headquarters in a growing part of Fayetteville, Arkansas. The Company has owned an interest in this land for many years. The property is zoned for commercial, office, and multi-family residential development. AWR continues to review with a joint venture partner various options for developing this property which would minimize the Company's initial capital expenditures but still enable it to retain an interest in any appreciation in value. This activity, however, does not represent a significant portion of the Company's business.

EMPLOYEES

At December 31, 1995, the Company had 667 employees, 88 of whom are represented under a collective bargaining agreement.

INDUSTRY SEGMENT AND STATISTICAL INFORMATION

The following portions of the 1995 Annual Report to Shareholders (filed as Exhibit 13 to this filing) are hereby incorporated by reference for the purpose of providing additional information about its business. Refer to page 27 (Note 9 to the financial statements) for information about industry segments and pages 30 and 31 ("Financial and Operating Statistics") for additional statistical information, including the average sales price per unit of gas produced and of oil produced and the average production cost per unit.

Item 2. PROPERTIES

The portions of the Registrant's 1995 Annual Report to Shareholders (filed as Exhibit 13 to this filing) listed below are hereby incorporated by reference for the purpose of describing its properties.

Refer to the Appendix (filed as part of Exhibit 13 to this filing) for information concerning areas of operation of the Company's gas distribution systems. For information concerning the Company's exploration and production areas of operation, also refer to the Appendix. See the table entitled "Operating Properties" at the Appendix for information concerning miles of pipe of the Company's gas distribution systems and for information regarding leasehold acreage and producing wells by geographic region of the Company's exploration and production segment. Also, see pages 24 through 26 (Notes 5 and 6 to the financial statements) for additional information about the Company's gas and oil operations. For information concerning capital expenditures, refer to page 14 ("Capital Expenditures" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations"). Also refer to page 31 ("Financial and Operating Statistics") for information concerning gas and oil wells drilled and gas and oil produced.

The following information is provided to supplement that presented in the 1995 Annual Report to Shareholders:

NET WELLS DRILLED DURING THE YEAR

Year	Exploratory Productive Wells	Exploratory Dry Holes	Total
1995	6.3	7.1	13.4
1994	4.7	1.8	6.5
1993	2.8	4.0	6.8

Year	Development Productive Wells	Development Dry Holes	Total
1995	37.5	19.4	56.9
1994	45.5	14.7	60.2
1993	37.9	10.5	48.4

WELLS IN PROGRESS AS OF DECEMBER 31, 1995

Type of Well	Gross	Net
Exploratory	8.0	5.1
Development	9.0	7.3
Total	17.0	12.4

Due to the insignificance of the Company's oil reserves and producing oil wells to its total reserves and producing wells, separate disclosure of gas and oil producing wells has not been made.

No individually significant discovery or other major favorable or adverse event has occurred since December 31, 1995.

During 1995, SEECO and SEPCO were required to file Form 23, "Annual Survey of Domestic Oil and Gas Reserves" with the Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 6 to the financial statements in the 1995 Annual Report to Shareholders. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share and includes reserves for only those properties where either SEECO or SEPCO is the operator.

Item 3. LEGAL PROCEEDINGS

The Company has been advised of a potential claim against it involving the disputed ownership of overriding royalty interests in a number of oil and gas properties and related matters. The Company has begun discussions with the claimant and has engaged special counsel to assist it in a preliminary investigation of the claim's merits. The Company is unable to predict at this time whether litigation will be commenced in respect of this claim or how the claim will ultimately be resolved. While the amount of the potential claim is significant in the aggregate, management believes, based on its preliminary investigation, that the Company's ultimate liability, if any, will not be material to its consolidated financial position or results of operations.

The Company and its subsidiaries are involved in various other legal proceedings arising in the ordinary course of business. While the outcome of lawsuits or other proceedings cannot be predicted with certainty, management expects these matters will not have a material adverse effect on the consolidated financial position or results of operations of the Company.

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

No matters were submitted during the fourth quarter of the fiscal year ended December 31, 1995, to a vote of security holders, through the solicitation of proxies or otherwise.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following is information with regard to executive officers of the Company:

Name	Age	Officer Position
Charles E. Scharlau.....	68	Chairman of the Board (since 1979), Southwestern Energy Company and Subsidiaries, and Chief Executive Officer (since 1968), Southwestern Energy Company.
Dan B. Grubb............	60	President and Chief Operating Officer (since 1992), Director (1988-1992), Southwestern Energy Company. Chairman and Chief Executive Officer of Grubb Industries, Inc., and Investor and Business Consultant (since 1988). Previously, President and Chief Operating Officer, Midcon Corporation (since 1987).
Stanley D. Green........	42	Executive Vice President - Finance and Corporate Development (since 1992), and Chief Financial Officer (since 1987), Vice President - Treasurer and Secretary (since 1987), Controller (since 1981), Southwestern Energy Company and Subsidiaries.
B. Brick Robinson.......	65	Executive Vice President and Chief Operating Officer (since 1988), Southwestern Energy Production Company and SEECO, Inc. (subsidiaries of Southwestern Energy Company). Previously, various positions with Occidental Petroleum Corporation and its subsidiaries, including Vice President, Far East and Domestic Frontier Exploration, Occidental International (since 1985).
Gregory D. Kerley.......	40	Vice President - Treasurer and Secretary (since 1992), and Chief Accounting Officer (since 1990), Controller (since 1990), Southwestern Energy Company and Subsidiaries. Previously, Treasurer and Controller, Agate Petroleum, Inc. (since 1984).

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 the Company's directors. Information concerning compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is presented in the definitive Proxy

Statement dated March 27, 1996, under the section entitled "Security Ownership of Directors, Nominees, and Executive Officers" and is incorporated herein by reference.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Shareholder Information on page 32 and "Common Stock Statistics" included in the Company's Financial and Operating Statistics on page 30 of the 1995 Annual Report to Shareholders (filed as Exhibit 13 to this filing) are hereby incorporated by reference for information concerning the market for and prices of the Company's Common Stock, the number of shareholders, and cash dividends paid.

The terms of the Company's long-term debt instruments and agreements impose restrictions on the payment of cash dividends. At December 31, 1995, $103.0 million of retained earnings was available for payment as cash dividends. These covenants generally limit the payment of dividends in a fiscal year to the total of net income plus $20.0 million less dividends paid and purchases, redemptions or retirements of capital stock during the period since January 1, 1990.

The Company paid dividends at an annual rate of $.24 per share in 1995 and 1994. While the Board of Directors intends to continue the practice of paying dividends quarterly, amounts and dates of such dividends as may be declared will necessarily be dependent upon the Company's future earnings and capital requirements.

Item 6. SELECTED FINANCIAL DATA, AND

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

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following portions of the 1995 Annual Report to Shareholders (filed as Exhibit 13 to this filing) are hereby incorporated by reference.

Refer to page 30 ("Financial and Operating Statistics") for selected financial data of the Company.

Refer to the text on pages 10 through 15 for "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Refer to pages 17 through 29 for financial statements and supplementary data.

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

There have been no changes in or disagreements with accountants on accounting and financial disclosure.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The definitive Proxy Statement to holders of the Company's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 13, 1996 (the 1996 Proxy Statement), is hereby incorporated by reference for the purpose of providing information about the identification of directors. Refer to the sections "Election of Directors" and "Security Ownership of Directors, Nominees, and Executive Officers" for information concerning the directors.

Information concerning executive officers is presented in Part I, Item 4 of this Form 10-K.

Item 11. EXECUTIVE COMPENSATION

The 1996 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation. Refer to the section "Executive Compensation."

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The 1996 Proxy Statement is hereby incorporated by reference for the purpose of providing information about security ownership of certain beneficial owners and management. Refer to the section "Security Ownership of Directors, Nominees, and Executive Officers" for information about security ownership of certain beneficial owners and management.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The 1996 Proxy Statement is hereby incorporated by reference for the purpose of providing information about related transactions. Refer to the section "Security Ownership of Directors, Nominees, and Executive Officers" for information about transactions with members of the Company's Board of Directors.

PART IV

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a)(1) The following consolidated financial statements of the Company and its subsidiaries, included on pages 17 through 29 of its 1995 Annual Report to Shareholders (filed as Exhibit 13 to this filing) and the report of independent auditors on page 16 of such report are hereby incorporated by reference:

Report of Independent Auditors.

Consolidated Balance Sheets as of December 31, 1995 and 1994.

Consolidated Statements of Income for the years ended December 31, 1995, 1994, and 1993.

Consolidated Statements of Cash Flows for the years ended December 31, 1995, 1994, and 1993.

Consolidated Statements of Retained Earnings for the years ended December 31, 1995, 1994, and 1993.

Notes to Consolidated Financial Statements, December 31, 1995, 1994, and 1993.

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

(3) The exhibits listed on the accompanying Exhibit Index (pages 15 - 17) are filed as part of, or incorporated by reference into, this Report.

(b) Reports on Form 8-K:

A Current Report on Form 8-K was filed on December 21, 1995, referencing the opinions of Cleary, Gottlieb, Steen and Hamilton and Jeffrey L. Dangeau, as to the validity of the Company's 6.70% Senior Notes due 2005, issued on December 5, 1995.

SIGNATURES

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

SOUTHWESTERN ENERGY COMPANY
(Registrant)

Dated: March 25, 1996

BY: /s/ STANLEY D. GREEN
Stanley D. Green,
Executive Vice President - Finance and Corporate Development, 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 March 25, 1996.

/s/ CHARLES E. SCHARLAU *Charles E. Scharlau*	*Director, Chairman, and Chief Executive Officer*
/s/ STANLEY D. GREEN *Stanley D. Green*	*Executive Vice President - Finance and Corporate Development, and Chief Financial Officer*
/s/ GREGORY D. KERLEY *Gregory D. Kerley*	*Vice President - Treasurer and Secretary, and Chief Accounting Officer*
/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. SANDERS *Charles E. Sanders*	*Director*

Supplemental Information to be Furnished With Reports Filed Pursuant to

Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act.

Not Applicable

EXHIBIT INDEX

Exhibit
No. Description

3. Articles of Incorporation and Bylaws of the Company (amended and restated Articles of Incorporation incorporated by reference to Exhibit 3 to Annual Report on Form 10-K for the year ended December 31, 1993); Bylaws of the Company (amended Bylaws of the Company incorporated by reference to Exhibit 3 to Annual Report on Form 10-K for the year ended December 31, 1994).

4.1 Shareholder Rights Agreement, dated May 5, 1989 (incorporated by reference to Exhibit 1 filed with the Company's Form 8-K on May 10, 1989).

4.2 Prospectus, Registration Statement, and Indenture on 6.70% Senior Notes due December 1, 2005 and issued December 5, 1995 (incorporated by reference to the Company's Forms S-3 and S-3/A filed on November 1, 1995, and November 17, 1995, respectively, and also to the Company's filings of a Prospectus and Prospectus Supplement on November 22, 1995, and December 4, 1995, respectively).

MATERIAL CONTRACTS:

10.1 Gas Purchase Contract between SEECO, Inc., and Arkansas Western Gas Company, dated July 24, 1978, as amended May 21, 1979, and Amended and Restated as of July 1, 1994 (incorporated by reference to Exhibit 10.1 to Annual Report on Form 10-K for the year ended December 31, 1994).

10.2 Agreement between Southwestern Energy Company, Arkansas Western Gas Company, Arkansas Power & Light Company and Associated Natural Gas Company, dated September 1, 1987, as amended February 22, 1988, and May 16, 1988 (original agreement and first amendment to the Agreement incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1987; second amendment to the Agreement thereto incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1988).

10.3 Gas Purchase Contract between SEECO, Inc. and Associated Natural Gas Company, dated October 1, 1990 (incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1990).

10.4 Compensation Plans:

(a) Summary of Southwestern Energy Company Annual and Long-Term Incentive Compensation Plan, effective January 1, 1985, as amended July 10, 1989 (replaced by Southwestern Energy Company Incentive Compensation Plan, effective January 1, 1993) (original plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1984; first amendment thereto incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

(b) Summary of Southwestern Energy Company Incentive Compensation Plan, effective January 1, 1993 (incorporated by reference to Exhibit 10.4(b) to Annual Report on Form 10-K for the year ended December 31, 1993).

Exhibit No.	Description

(c) Nonqualified Stock Option Plan, effective February 22, 1985, as amended July 10, 1989 (replaced by Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993) (original plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1985; amended plan incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

(d) Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993 (incorporated by reference to the appendix filed with the Company's definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 26, 1993).

(e) Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors, dated April 7, 1993 (incorporated by reference to the appendix filed with the Company's definitive Proxy Statement to holders of the Registrant's Common Stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Shareholders on May 26, 1993).

10.5 Southwestern Energy Company Supplemental Retirement Plan, adopted May 31, 1989, and Amended and Restated as of December 15, 1993, and as further amended February 1, 1996 (amended and restated plan incorporated by reference to Exhibit 10.5 to Annual Report on Form 10-K for the year ended December 31, 1993; amendment dated February 1, 1996, filed herewith).

10.6 Southwestern Energy Company Supplemental Retirement Plan Trust, dated December 30, 1993 (incorporated by reference to Exhibit 10.6 to Annual Report on Form 10-K for the year ended December 31, 1993).

10.7 Southwestern Energy Company Nonqualified Retirement Plan, effective October 4, 1995 (filed herewith).

10.8 Split-Dollar Life Insurance agreement for Stanley D. Green, effective February 1, 1996 (filed herewith).

10.9 Executive Sever[illegible]nt for Charles E. Scharlau, effective August 4, 1989 (incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

10.10 Executive Severance Agreement for Stanley D. Green, effective August 4, 1989 (incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

10.11 Executive Severance Agreement for B. Brick Robinson, effective August 4, 1989 (incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1989).

10.12 Executive Severance Agreement for Dan B. Grubb, effective July 8, 1992 (incorporated by reference to Exhibit 10.13 to Annual Report on Form 10-K for the year ended December 31, 1992).

10.13 Executive Severance Agreement for Gregory D. Kerley, effective December 14, 1994 (incorporated by reference to Exhibit 10.11 to Annual Report on Form 10-K for the year ended December 31, 1994).

Exhibit
No. Description

10.14 Employment Agreement for Charles E. Scharlau, dated December 18, 1990, effective January 1, 1991, as amended December 7, 1994 (original agreement incorporated by reference to Exhibit 10 to Annual Report on Form 10-K for the year ended December 31, 1990; amended agreement incorporated by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 1994).

10.15 Employment Agreement for Dan B. Grubb, effective July 8, 1992 (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K for the year ended December 31, 1992).

10.16 Form of Indemnity Agreement, between the Company and each officer and director of the Company (Incorporated by reference to Exhibit 10.20 to Annual Report on Form 10-K for the year ended December 31, 1991).

10.17 Agreement for Sale of Partnership Interest between Southwestern Energy Pipeline Company and GRUBB NOARK Pipeline, Inc., dated July 24, 1992 (incorporated by reference to Exhibit 10.25 to Annual Report on Form 10-K for the year ended December 31, 1992).

13. 1995 Annual Report to Shareholders, except for those portions not expressly incorporated by reference into this Report. Those portions not expressly incorporated by reference are not deemed to be filed with the Securities and Exchange Commission as part of this Report (filed herewith).

22. Subsidiaries of the Registrant (incorporated by reference to Exhibit 22 to Annual Report on Form 10-K for the year ended December 31, 1992).

AMENDMENT NUMBER 1
TO THE
SOUTHWESTERN ENERGY COMPANY
SUPPLEMENTAL RETIREMENT PLAN

WHEREAS, the Southwestern Energy Company (the "Company") maintains the Southwestern Energy Company Supplemental Retirement Plan (the "SERP"); and

WHEREAS, it is desirable to amend the SERP to provide an offset to benefits payable to a participant or a participant's beneficiary under the SERP for any benefits provided under any split-dollar life insurance agreement between such participant and the Company and to change the timing of the benefit payments under the SERP.

NOW, THEREFORE, effective February 1, 1996, the SERP is amended as follows:

ARTICLE III
UNFUNDED BENEFITS

1. Section B.1 is amended in its entirety to read as follows:

"The Actuarial Equivalent of a Participant's or Beneficiary's Unfunded Benefit under the Plan shall be paid to the Participant or Beneficiary in a single lump sum on the later of (a) the first day of the month following the one-year anniversary of the Participant's termination of employment with the Company or (b) the date that benefit payments under the Pension Plan to such Participant or Beneficiary commence; provided, however, that a Participant may elect that the Actuarial Equivalent of his (or, in the event of the Participant's death, his Beneficiary's) Unfunded Benefit under the Plan be paid in the form of an annuity, beginning at the same time and in the same form as the Participant's or Beneficiary's benefit under the Pension Plan is paid, by filing a written election with the Committee, on a form provided by the Committee, at least one year before such Participant's termination of employment with the Company. No election or revocation of an election shall be effective if it is received by the Committee less than one year prior to the Participant's termination of employment."

2. A new Section D is added to read as follows:

"D. Offset for Certain Benefits Payable Under Split-Dollar Life Insurance Agreements.

1. Offset Value.

Some of the Participants under this Plan own life insurance policies (the "Policies") purchased on their behalf by the Corporation. The exercise of ownership rights under these Policies by each Participant is, however, subject to certain conditions (set forth in a "Split-Dollar Insurance Agreement" between the Participant and the Corporation, pursuant to which the Corporation holds a security interest on the Policy) and, if the Participant fails to meet the conditions set forth in the Split-Dollar Life Insurance Agreement, the Corporation may exercise its security interest in the Policy and cause the Participant to lose certain benefits under the Policy. In the event that a Participant satisfies the condition specified in Section 4 or 5 of the Split-Dollar Life Insurance Agreement, so that the Participant or his or her beneficiary becomes entitled to exercise rights free from the Corporation's security interest under one of those sections, or the Corporation's security interest is otherwise released, the value of those benefits shall constitute an offset to the Participant's Unfunded Benefits otherwise payable under this Plan. As the case may be, this offset (the "Offset Value") shall be equal to the cash surrender value of the Policy at the time the Participant becomes entitled to exercise rights free from the Company's security interest, or in the case of the Participant's death, the death benefits payable to the beneficiary under the Policy. The Actuarial Equivalent of the Offset Value shall be compared to the Actuarial Equivalent of the Unfunded Benefits payable under this Plan (the "Plan Value"), and the Plan Value shall be reduced by the Actuarial Equivalent of the Offset Value at the time and in the manner described in Section D.2 or Section D.3 of this Article III.

2. Manner and Calculation of Payment.

If, at the time the Participant terminates employment, the Plan Value exceeds the Actuarial Equivalent of the Offset Value, the excess of the Plan Value over the Actuarial Equivalent of the Offset Value shall be paid to the Participant or Beneficiary at the time and in the manner provided under Section B.1 of this Article III; provided, however, that if such excess is less than $10,000, such excess shall be paid immediately to the Participant or Beneficiary in a cash lump sum. For this purpose, the Plan Value shall be calculated by assuming that the Participant or Beneficiary receives or commences receiving benefits under this Plan and the Pension Plan on the earliest date that such benefits become payable.

3. Payment of Certain Benefits.

If the policy described in Section D.1 of this Article III insures the life of an individual other than the Participant (the "Insured party"), and if such Insured Party dies prior to the Participant's becoming eligible for benefits under the Plan, and if the Participant or Beneficiary subsequently becomes eligible for benefits hereunder, the Plan Value (as defined in Section D.1 of this Article III) shall then be offset by the Actuarial Equivalent of the amount equal to the death benefit previously paid to the Participant or the Participant's beneficiary pursuant to the Split-Dollar Life Insurance Agreement divided by the Tax Adjustment Factor (as defined below). Any remaining Plan Value shall thereupon be paid to the Participant or Beneficiary in a cash lump sum.

4. Tax Adjustment Factor.

For purposes of this Section D of Article III, Tax Adjustment Factor shall mean a number, determined by the Committee, which is equal to one minus the sum of (a) the highest marginal federal personal income tax rate then in effect and (b) the effective highest marginal state income tax rate in the state in which the Participant resides, net after the effect of the deduction for such state income tax for federal income tax purposes."

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officers this 1st day of February, 1996.

SOUTHWESTERN ENERGY COMPANY

By __________________________

Its__________________________

SOUTHWESTERN ENERGY COMPANY
NONQUALIFIED RETIREMENT PLAN

PLAN DOCUMENT

TABLE OF CONTENTS

Page

Page

ARTICLE I - PURPOSE OF PLAN

1.1 PURPOSE OF PLAN. The Company intends and desires by the adoption of this Plan to recognize the value to the Company of the past and present services of Eligible Employees covered by the Plan and to encourage and assure their continued service with the Company by making more adequate provisions for their future retirement security.

This Plan has been adopted to provide certain select management and highly compensated employees of Southwestern Energy Company covered under the Southwestern Energy Company 401(k) Savings Plan (the "Basic Plan") the opportunity to accumulate deferred compensation which cannot be accumulated under the Basic Plan because of the limitations on deferrals under Code Section 402(g) (the "Deferral Limit"), the limitations on annual additions under Code Section 415 (the "415 Limit"), the limitations on tax-qualified pension plan benefits under Code Section 401(a)(17) (the "Pay Cap"), and because Deferral Contributions and Matching Contributions have been required to be returned under the Basic Plan because of the nondiscrimination rules under Code Sections 401(k)(3) ("ADP Restrictions") or 401(m)(2) ("ACP Restrictions").

This Plan is intended to be "a plan which is unfunded and maintained by an employer primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees" within the meaning of Sections 201(2) and 301(a)(3) of the Employee Retirement Income Security Act of 1974 ("ERISA") and shall be interpreted and administered in a manner consistent with that intent.

ARTICLE II - DEFINITIONS

2.1 ACCOUNT means those separate accounts established and maintained under the Plan in the name of each Participant as required pursuant to the provisions of Article VII.

2.2 BASIC PLAN means the Southwestern Energy Company 401(k) Savings Plan.

2.3 BENEFICIARY means a Participant's beneficiary or beneficiaries identified on the Participant Enrollment and Election Form.

2.4 BOARD means the Board of Directors of Southwestern Energy Company.

2.5 CODE means the Internal Revenue Code of 1986 and the regulations thereunder, as amended from time to time.

2.6 COMMITTEE means the Retirement Committee appointed by the Board.

2.7 COMPANY means Southwestern Energy Company or any company which is a successor as a result of merger, consolidation, liquidation, transfer of assets, or other reorganization.

2.8 COMPANY CONTRIBUTION means an amount contributed by the Company pursuant to the provisions of Article VI.

2.9 COMPENSATION means base salary or wages, plus overtime, bonuses, commissions, etc., which is paid the employee by the Company for the performance of duties during the Plan Year.

2.10 DEFERRAL CONTRIBUTION means those contributions by the Company to the Basic Plan for a Plan Year on behalf of and on account of the qualified cash or deferral elections within the meaning of Code Section 401(k) made by the participants in the Basic Plan.

2.11 EFFECTIVE DATE means the date on which the Company adopts the Plan.

2.12 ELIGIBLE EMPLOYEE means, for any Plan Year (or applicable portion thereof), a person employed by the Company who is determined by the Committee to be a member of a select group of management or highly compensated employees, who is designated by the Committee to be eligible under the Plan, and who is a participant in the Basic Plan. By fifteen days prior to the beginning of a Plan Year, the Company shall notify those individuals, if any, who will be Eligible Employees for the next Plan Year. If the Company determines that an employee first becomes an Eligible Employee during a Plan Year, the Company shall notify such employee of its determination and of the date during the Plan Year on which the employee shall first become an Eligible Employee.

2.13 ENTRY DATE means the "Entry Date" as that term is defined in the Basic Plan.

2.14 MATCHING CONTRIBUTION means those contributions by the Company to the Basic Plan for a Plan Year on account of the Deferral Contributions made during that Plan Year by the participants in the Basic Plan.

2.15 NONQUALIFIED DEFERRAL CONTRIBUTION means Compensation that is due to be earned and which would otherwise be paid to the Participant, which the Participant elects to defer under the Plan, determined without regard to the Deferral Limit, the 415 Limit, the Pay Cap or the ADP Restrictions under the Basic Plan, and which is contributed on behalf of each Participant by the Company pursuant to the provisions of Article IV.

2.16 NONQUALIFIED MATCHING CONTRIBUTION means an amount contributed by the Company on account of the Participant's Nonqualified Deferral Contribution, pursuant to the provisions of Article V.

2.17 PARTICIPANT means any person so designated in accordance with the provisions of Article III, including, where appropriate according to the context of the Plan, any former employee who is or may become (or whose Beneficiaries may become) eligible to receive a benefit under the Plan.

2.18 PARTICIPANT ENROLLMENT AND ELECTION FORM means the form on which a Participant elects to defer Compensation hereunder and on which the Participant makes certain other designations as required thereon.

2.19 PLAN means this Southwestern Energy Company Non-Qualified Retirement Plan.

2.20 PLAN YEAR means the "Plan Year" as that term is defined in the Basic Plan.

2.21 TRANSFER DATE means the date on which amounts credited to each Participant's Account for the Plan Year are transferred to the Basic Plan.

2.22 TRUST means the trust fund established pursuant to the Plan.

2.23 TRUSTEE means the trustee named in the agreement establishing the Trust and such successor and/or additional trustees as may be named pursuant to the terms of the agreement establishing the Trust.

2.24 VALUATION DATE means the last day of each Plan Year and any other date that the Company, in its sole discretion, designates as a Valuation Date.

ARTICLE III - ELIGIBILITY AND PARTICIPATION

3.1 REQUIREMENTS. Every Eligible Employee as of the Effective Date shall be eligible to become a Participant on the Effective Date. Every other Eligible Employee shall be eligible to become a Participant on the first Entry Date occurring on or after the date on which he or she becomes an Eligible Employee. No individual shall become a Participant, however, if he or she is not an Eligible Employee on the date his or her participation is to begin.

Participation in the Plan is voluntary. In order to participate, an otherwise Eligible Employee must execute a valid Participant Enrollment and Election Form in such manner as the Company may require and must agree to make Nonqualified Deferral Contributions as provided in Article IV.

3.2 RE-EMPLOYMENT. If a Participant whose employment with the Company is terminated is subsequently re-employed, he or she shall become a Participant in the Plan in accordance with the provisions of Section 3.1 of this Article.

3.3 CHANGE OF EMPLOYMENT CATEGORY. During any period in which a Participant remains in the employ of the Company, but either ceases to be an Eligible Employee or a participant in the Basic Plan, he or she shall not be eligible to make additional Nonqualified Deferral Contributions under this Plan.

ARTICLE IV - NONQUALIFIED DEFERRAL CONTRIBUTIONS

4.1 NONQUALIFIED DEFERRAL ELECTIONS. In accordance with rules established by the Company, a Participant may elect to make a Nonqualified Deferral Contribution with respect to a Plan Year by use of a Participant Enrollment and Election Form at the same time and in the same manner as the Participant would elect to have a Deferral Contribution made on his or her behalf under the Basic Plan. In addition, a participant in the Basic Plan who becomes a Participant during the Plan Year may elect to make a Nonqualified Deferral Contribution with respect to the remaining portion of the Plan Year by use of a Participant Enrollment and Election Form at the same time and in the same manner as if the Participant had become eligible to elect to have a Deferral Contribution made on his or her behalf under the Basic Plan.

4.2 PAYROLL DEDUCTIONS. Nonqualified Deferral Contributions shall be made through payroll deductions. The Participant may change the amount of his or her Nonqualified Deferral Contribution amount by delivering to the Company at least fifteen days prior to the beginning of any quarter a new Participant Enrollment and Election Form, at the same time and in the same manner required for changes to a Deferral Contribution under the Basic Plan, with such change being first effective for Compensation to be earned in the first payroll period of the quarter. Once made, a Nonqualified Deferral Contribution payroll deduction election shall continue in force indefinitely, until changed by the Participant on a subsequent Participant Enrollment and Election Form delivered to the Company.

4.3 TIMING OF CONTRIBUTION. Nonqualified Deferral Contributions shall be made at the same time and in the same manner as Deferral Contributions.

ARTICLE V - NONQUALIFIED MATCHING CONTRIBUTIONS

5.1 NONQUALIFIED MATCHING PERCENTAGE. The Company shall make a Nonqualified Matching Contribution on behalf of a Participant, and on account of the Participant's Nonqualified Deferral Contributions for a Plan Year, at the same rate as the Matching Contribution for the Plan Year. Nonqualified Matching Contributions will be made only to the extent they do not exceed three (3) percent of the Participant's base salary and wages, excluding overtime, bonuses and commissions for the Plan Year.

5.2 TIMING OF MATCH. Nonqualified Matching Contributions shall be made at the same time and in the same manner as Matching Contributions.

ARTICLE VI - COMPANY CONTRIBUTIONS

6.1 COMPANY CONTRIBUTION. In its sole discretion, the Company may make a Company Contribution on behalf of Participant, in addition to any Nonqualified Matching Contributions, in an amount determined by the Company in accordance with (a) and/or (b) below:

(a)A percentage of each Participant's Compensation for the Plan Year;

(b)A percentage of some or all of the Participant's Nonqualified Deferral Contribution for the Plan Year.

6.2 TIMING OF CONTRIBUTION. Company Contributions shall be made as soon as administratively feasible after declared by the Board.

ARTICLE VII - PLAN ACCOUNTS

7.1 ESTABLISHMENT OF ACCOUNTS. There shall be established and maintained by the Company separate Accounts in the name of each Participant, as required and as described in this Article VII.

7.2 NONQUALIFIED DEFERRAL ACCOUNT. The Company shall establish an Account to which are credited a Participant's Nonqualified Deferral Contributions, plus amounts equal to any income, gains, or losses (to the extent realized, based upon fair market value of the Account's assets) attributable or allocable to the Participant's Account.

7.3 NONQUALIFIED MATCHING ACCOUNT. The Company shall establish an Account to which are credited a Participant's Nonqualified Matching Contributions, plus amounts equal to any income, gains, or losses (to the extent realized, based upon fair market value of the Account's assets) attributable or allocable to the Participant's Account.

7.4 COMPANY CONTRIBUTION ACCOUNT. The Company shall establish an Account to which are credited a Participant's Company Contributions, plus amounts equal to any income, gains, or losses (to the extent realized, based upon fair market value of the Account's assets) attributable or allocable to the Participant's Account.

7.5 ALLOCATION OF INCOME. The Company shall have the discretion to allocate such income, gains, or losses among Accounts pursuant to such allocation rules as the Company deems to be reasonable and administratively practicable.

ARTICLE VIII-- TRANSFERS TO BASIC PLAN

8.1 IN GENERAL. A transfer made pursuant to this Article shall not constitute a Payment of Benefits, as that phrase is referenced in Article XI.

8.2 NONQUALIFIED DEFERRAL ACCOUNT TRANSFERS. As soon as administratively feasible after the end of a Plan Year, but in no event later than 90 days following the end of that Plan Year, the Company shall transfer to the Basic Plan all the Nonqualified Deferral Contributions credited to each Participant's Nonqualified Deferral Account for that Plan Year, but in no event shall an amount be transferred that would cause the Basic Plan to be negatively impacted by the existing ADP Restrictions for such Plan Year.

8.3 NONQUALIFIED MATCHING ACCOUNT TRANSFERS. As soon as administratively feasible after the end of a Plan Year, but in no event later than 90 days following the end of that Plan Year, the Company shall transfer to the Basic Plan all the Nonqualified Matching Contributions credited to each Participant's Nonqualified Matching Account for that Plan Year, but in no event shall an amount be transferred that would cause the Basic Plan to be negatively impacted by the existing ACP Restrictions for such Plan Year.

8.4 FREQUENCY OF TRANSFERS. In its sole discretion, the Company may make multiple transfers under Sections 8.2 and 8.3 during the Plan Year.

8.5 RESTRICTION. No transfer shall occur under Sections 8.2 or 8.3 unless the terms of the Basic Plan specifically provide that such transfers will be accepted.

8.6 EMPLOYEE ELECTION. An Eligible Employee may make an election prior to the end of the Plan Year to not make the transfers under Sections 8.2 and 8.3. This election can be for all or a portion of the transfers.

ARTICLE IX - ALLOCATION OF FUNDS

9.1 ALLOCATION OF EARNINGS OR LOSSES ON ACCOUNTS. Each Participant's Account shall be invested in such investments as the Trustee shall determine. The Trustee may (but is not required to) consider the Participant's investment preferences when investing amounts credited to the Participant's Accounts. Such investment preferences shall be related to the Trustee at the time and in the manner prescribed by the Company, in its sole discretion. The Participant's Accounts will be credited or debited with the increase or decrease in the realizable net asset value or credited interest, as applicable, of each investment, as follows. As of each Valuation Date, an amount equal to the net increase or decrease in realizable net asset value or credited interest, as applicable (as determined by the Trustee), of each investment option within the Trust since the preceding Valuation Date shall be allocated among all Participants' Accounts to be invested in that investment option in accordance with the ratio which the portion of the Account of each Participant which is to be invested within that investment option, determined as provided herein, bears to the aggregate of all amounts to be invested within that investment option.

9.2 ACCOUNTING FOR DISTRIBUTIONS. As of the date of any distribution under the Plan to a Participant or his or her Beneficiary or Beneficiaries, such distribution shall be charged to the applicable Participant's Account.

9.3 INTERIM VALUATIONS. If it is determined by the Company that the value of the Trust as of any date on which distributions are to be made differs materially from the value of the Trust on the prior Valuation Date upon which the distribution is to be based, the Company, in its discretion, shall have the right to designate any date in the interim as a Valuation Date for the purpose of revaluing the Trust so that the Account from which the distribution is being made will, prior to the distribution, reflect its share of such material difference in value.

ARTICLE X - VESTING

10.1 NONQUALIFIED DEFERRAL CONTRIBUTIONS. A Participant shall always be one hundred percent (100%) vested in amounts credited to his or her Nonqualified Deferral Account.

10.2 NONQUALIFIED MATCHING CONTRIBUTIONS. A Participant shall always have the same vesting percentage in his or her Nonqualified Matching Account as he or she has in his or her Matching Contribution account under the Basic Plan. However, in the event of a Change in Control, as defined in Section 11.3, a Participant shall become 100% vested in his or her Nonqualified Matching Account if the Participant's employment terminates with the Company during the two year period prior to or following the Change in Control.

10.3 COMPANY CONTRIBUTIONS. A Participant 's Company Contribution Account will be subject to the same vesting schedule and forfeiture provisions as his or her Matching Contribution Account under the Basic Plan. However, in the event of a Change in Control, as defined in Section 11.3, a Participant shall become 100% vested in his or her Company Contribution Account if the Participant's employment terminates with the Company during the two year period prior to or following the Change in Control.

ARTICLE XI - PAYMENTS OF BENEFITS

11.1 PAYMENTS OF BENEFITS. The benefit payable under this Plan on account of a Participant's termination of employment, retirement, disability, hardship, or death shall be distributed in a cash lump sum as soon as practicable and no later than sixty (60) days after the earlier of such termination of employment, retirement, incurrence of disability (as determined by the Committee), hardship, or death. Any death benefit payable under the Plan shall be payable to the Participant's Beneficiary. In the event of a Change in Control, as defined in Section 11.3, any additional benefit pursuant to an increase in vesting as described in Section 10.2 and 10.3 under the Plan shall be distributed in a cash lump sum as soon as practicable and no later than sixty (60) days after the Change in Control.

11.2 PAYMENTS UPON HARDSHIP. In the event of a hardship of the Participant, the Participant may apply to the Company for the distribution of all or any part of his or her Accounts in the same manner, and under the same terms and conditions, as under the Basic Plan. Upon a finding of hardship under the Basic Plan, the Company shall instruct the Trustee to make the appropriate distribution to the Participant from amounts contributed to the Trust by the Company in respect of the Participant's Accounts. In no event shall the aggregate amount of the distribution exceed the value of the Participant's Accounts. For purposes of this Section, the value of the Participant's Accounts shall be determined as of the date of the distribution. A distribution may be made under this Section only with the consent of the Company's Committee.

11.3 PAYMENTS UPON CHANGE IN CONTROL. Notwithstanding any other provision of this Plan, a Participant's Account shall be distributed to the Participant in a cash lump-sum within sixty (60) days after a Change in Control. For purposes of this Section, a "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 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 the Company representing 20% or more of the combined voting power of the Company's then outstanding securities, excluding any employee benefit plan sponsored or maintained by the Company (or any trustee of such plan acting as trustee);

(ii) the Company's stockholders approve an agreement to merge or consolidate the Company with another corporation (other than a corporation 50% or more of which is controlled by, or is under common control with, the Company);

(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 the Company 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; or

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

ARTICLE XII - COMMITTEE ADMINISTRATION

12.1 COMMITTEE. The Committee shall administer, construe, and interpret this Plan and shall determine, subject to the provisions of this Plan in a manner consistent with the administration of the Basic Plan, the Eligible Employees who become Participants in the Plan from time to time and the amount, if any, due a Participant (or his or her Beneficiary) under this Plan. No member of the Committee shall be liable for any act done or determination made in good faith. No member of the Committee who is a Participant in this Plan may vote on matters affecting his or her personal benefit under this Plan, but any such member shall otherwise be fully entitled to act in matters arising out of or affecting this Plan notwithstanding his or her participation herein. In carrying out its duties herein, the Committee shall have discretionary authority to exercise all powers and to make all determinations, consistent with the terms of the Plan, in all matters entrusted to it, and its determinations shall be given deference and shall be final and binding on all interested parties. In the event of a Change in Control, as defined in Section 11.3, all investment powers of the Committee shall be terminated and such investment powers shall be transferred to the Trustee. Such investment powers will then be exercisable at the sole discretion of the Trustee, subject to the terms of the Trust.

ARTICLE XIII--THE TRUST

13.1 ESTABLISHMENT OF TRUST. The Company shall establish the Trust with the Trustee, pursuant to such terms and conditions as are set forth in the Trust agreement to be entered into between the Company and the Trustee. The Trust is intended to be treated as a "grantor" trust under the Code, and the establishment of the Trust is not intended to cause Participants to realize current income on amounts contributed thereto, and the Trust shall be so interpreted.

ARTICLE XIV--ADMINISTRATION

14.1 ADMINISTRATIVE AUTHORITY. Except as otherwise specifically provided herein, the Company shall have the sole responsibility for and the sole control of the operation and administration of the Plan, and shall have the power and authority to take all actions including the right to amend or terminate the Plan, and to make all decisions and interpretations which may be necessary or appropriate in order to administer and operate the Plan, including, without limiting the generality of the foregoing, the power, duty, and responsibility to:

(a) Resolve and determine all disputes or questions arising under the Plan, including the power to determine the rights of Eligible Employees, Participants, and Beneficiaries, and their respective benefits, and to remedy any ambiguities, inconsistencies, or omissions in the Plan.

(b) Adopt such rules of procedure and regulations as in its opinion may be necessary for the proper and efficient administration of the Plan and as are consistent with the Plan.

(c) Implement the Plan in accordance with its terms and the rules and regulations adopted as above.

(d) Make determinations with respect to the eligibility of any Eligible Employee as a Participant and make determinations concerning the crediting and distribution of Plan Accounts.

(e) Appoint any persons or firms, or otherwise act to secure specialized advice or assistance, as it deems necessary or desirable in connection with the administration and operation of the Plan, and the Company shall be entitled to rely conclusively upon, and shall be fully protected in any action or omission taken by it in good faith reliance upon the advice or opinion of such firms or persons. The Company shall have the power and authority to delegate from time to time by written instrument all or any part of its duties, powers, or responsibilities under the Plan, both ministerial and discretionary, as it deems appropriate, to any person or committee, and in the same manner to revoke any such delegation of duties, powers, or responsibilities. Any action of such person or committee in the exercise of such delegated duties, powers, or responsibilities shall have the same force and effect for all purposes hereunder as if such action had been taken by the Company. Further, the Company may authorize one or more persons to execute any certificate or document on behalf of the Company, in which event any person notified by the Company of such authorization shall be entitled to accept and; conclusively rely upon any such certificate or document executed by such person as representing action by the Company until such third person shall have been notified of the revocation of such authority. In the event of a Change in Control, as defined in Section 11.3, the Company must notify the Participants prior to terminating the Trustee pursuant to this Section 14.1(e).

14.2 MUTUAL EXCLUSION OF RESPONSIBILITY. Neither the Trustee nor the Company shall be obliged to inquire into or be responsible for any act or failure to act, or the authority therefor, on the part of the other.

14.3 UNIFORMITY OF DISCRETIONARY ACTS. Whenever in the administration or operation of the Plan discretionary actions by the Company are required or permitted, such actions shall be consistently and uniformly applied to all persons similarly situated, and no such action shall be taken which shall discriminate in favor of any particular person or group of persons.

14.4 LITIGATION. Except as may be otherwise required by law, in any action or judicial proceeding affecting the Plan, no Participant or Beneficiary shall be entitled to any notice or service of process, and any final judgment entered in such action shall be binding on all persons interested in, or claiming under, the Plan.

14.5 PAYMENT OF ADMINISTRATION EXPENSES. All expenses incurred in the administration and operation of the Plan and the Trust, including any taxes payable by the Company in respect of the Plan or Trust or payable by or from the Trust pursuant to its terms, shall be paid by the Company.

14.6 CLAIMS PROCEDURE.

(a) Notice of Claim. Any Eligible Employee or beneficiary, or the duly authorized representative of an Eligible Employee or beneficiary, may file with the Committee a claim for a Plan benefit. Such a claim must be in writing on a form provided by the Committee and must be delivered to the Committee, in person or by mail, postage prepaid. Within ninety (90) days after the receipt of such a claim, the Committee shall send to the claimant, by mail, postage prepaid, a notice of the granting or the denying, in whole or in part, of such claim, unless special circumstances require an extension of time for processing the claim. In no event may the extension exceed ninety (90) days from the end of the initial period. If such an extension is necessary, the claimant will be given a written notice to this effect prior to the expiration of the initial ninety (90) day period. The Committee shall have full discretion to deny or grant a claim in whole or in part in accordance with the terms of the plan. If notice of the denial of a claim is not furnished in accordance with this Section, the claim shall be denied and the claimant shall be permitted to exercise his or her right to review pursuant to Sections 14.6(c) and 14.6(d) of the Plan, as applicable.

(b) Action on Claim. The Committee shall provide to every claimant who is denied a claim for benefits a written notice setting forth, in a manner calculated to be understood by the claimant:

(i) The specific reason or reasons for the denial;

(ii) A specific reference to the pertinent Plan provisions on which the denial is based;

(iii) A description of any additional material or information necessary of the claimant to perfect the claim and an explanation of why such material or information is necessary; and

(iv) An explanation of the Plan's claim review procedure.

(c) Review of Denial. Within sixty (60) days after the receipt by a claimant of written notification of the denial (in whole or in part) of a claim, the claimant or the claimant's duly authorized representative, upon written application to the Committee, delivered in person or by certified mail, postage prepaid, may review pertinent documents and may submit to the Committee, in writing, issues and comments concerning the claim.

(d) Decision on Review. Upon the Committee's receipt of a notice of a request for review, the Committee shall make a prompt decision on the review and shall communicate the decision on review in writing to the claimant. The decision on review shall be written in a manner calculated to be understood by the claimant and shall include specific reasons for the decision and specific references to the pertinent Plan provisions on which the decision is based. The decision on review shall be made not later than sixty (60) days after the Committee's receipt of a request for a review, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered not later than one hundred twenty
(120) days after receipt of the request for review. If an extension is necessary, the claimant shall be given written notice of the extension by the Committee prior to the expiration of the initial sixty (60) day period. If notice of the decision on review is not furnished in accordance with this Section, the claim shall be denied on review.

14.7 LIABILITY OF COMMITTEE, INDEMNIFICATION. To the extent permitted by law, the Committee or any Company employee shall not be liable to any person for any action taken or omitted in connection with the interpretation and administration of this Plan unless attributable to his or her own bad faith or willful misconduct.

14.8 EXPENSES. The cost of the establishment of the Plan and the adoption of the Plan by Company, including but not limited to legal and accounting fees, shall be borne by the Company.

14.9 TAXES. All amounts payable hereunder shall be reduced by any and all federal, state, and local taxes imposed upon an Eligible Employee or his or her beneficiary which are required to be paid or withheld by Company. The determination of Company regarding applicable income and employment tax withholding requirements shall be final and binding on the Eligible Employee.

14.10 ATTORNEY'S FEES. Company shall pay the reasonable attorney's fees incurred by any Eligible Employee in an action brought against Company to enforce Eligible Employee's rights under the Plan, provided that such fees shall only be payable in the event that the Eligible Employee prevails in such action.

ATTEST:		*SOUTHWESTERN ENERGY COMPANY*
/s/ GREG D.KERLEY	*By:*	*/s/ CHARLES E. SCHARLAU*
Greg D. Kerley *Vice President -* *Treasurer and Secretary*		*Charles E. Scharlau* *Chairman and Chief Executive Officer*

[SEAL] Date: ____________________________

Effective Date: October 4, 1995

SPLIT-DOLLAR LIFE INSURANCE AGREEMENT

This Agreement is entered into as of February 1, 1996 by and between Southwestern Energy Company (the "Company") and Stanley D. Green ("Employee") inreference to the following facts:

1. Employee is a valued employee of the Company.

2. The Company has simultaneously with the execution of this Agreement caused Pacific Mutual Life Insurance Company (the "Insurance Company") to issue and deliver to Employee policy number 1A23067760 (the "Policy") on the life of Employee. The first annual premium has been paid by the Company as of the date of this Agreement.

3. For purposes of this Agreement, the Company and any subsidiary of the Company shall constitute the "Employer." For this purpose, a subsidiary is a corporation which is a member of a controlled group of corporations (within the meaning of Section 414(b) of the Internal Revenue Code of 1986, as amended (the "Code")) of which the Company is a member. If Employee is employed by a corporation which, as a result of a sale or other corporate reorganization, ceases to be a member of such controlled group, such sale or other corporate reorganization shall be treated as a termination of Employee by Employer without Cause (as defined in Section 8) unless immediately following the event and without any break in employment the Employee remains employed by the Company or another corporation which is a member of the controlled group of corporations.

NOW THEREFORE, in consideration of the facts set forth above and the various promises and covenants set forth below, the parties to this Agreement agree as follows:

1. Ownership of Policy.

The Company acknowledges that Employee is the owner of the Policy and that Employee is entitled to exercise all of his or her ownership rights granted by the terms of the Policy, except to the extent that the power of the Employee to exercise those rights is specifically limited by this Agreement. Except as so limited, it is the expressed intention of the parties to reserve to Employee all rights in and to the Policy granted to its owner by the terms thereof, including, but not limited to, the right to change the beneficiary of that portion of the proceeds to which Employee is entitled under Section 4 of this Agreement and the right to exercise settlement options.

2. The Company's Security Interest.

The Company's security interest in the Policy is conditioned upon its satisfactorily performing all of the covenants under this Agreement. Each period covered by any individual premium payment described in Section 3 shall be considered a discrete extension of the Company's security interest in the Policy. The Company shall not have nor exercise any right in and to the Policy which could, in any way, endanger, defeat, or impair any of the rights of Employee in the Policy, including by way of illustration any right to collect the proceeds of the Policy in excess of the amount due the Company as provided in this Agreement and in the Policy. The only rights in and to the Policy granted to the Company in this Agreement shall be limited to the Company's security interest in and to the cash value of the Policy, as defined herein, and a portion of the death benefit of the Policy as hereinafter provided (the "Security Interest"). The Company shall not assign any of its Security Interest in the Policy to anyone other than Employee.

3. Premium payments.

Until (a) Employee files a notice with the Company pursuant to Section 10 electing a Security Release Date (as defined in Section 10 below), (b) Employee otherwise attains his or her Security Release Date, or (c) Employee's employment with the Company is terminated for any reason, whichever occurs earliest, the Company agrees to pay premiums under the Policy in amounts such that premiums (not including the initial premium) received by each anniversary date are at least equal to the "cumulative cost of term insurance" (as defined in the Policy) from the first anniversary date through the period ending twelve months after the anniversary date in question. The premium payment shall be transmitted directly by the Company to the Insurance Company. Consistent with the preceding sentences, prior to the release of the Company's Security Interest in the Policy, Employee and the Company agree that the Company shall from time to time designate one or more individuals (the "Designee"), who may be officers of the Company, who shall be entitled to adjust the death benefit under the Policy; provided, however, that the Designee may only increase, but not decrease, the death benefit in effect on the date that the Policy is issued. During the period of time that this Agreement is in effect, Employee irrevocably agrees that all dividends paid on the Policy shall be applied to purchase from the Insurance Company additional paid-up life insurance on the life of Employee.

4. Death of Employee while employed by Employer.

(a) If Employee dies prior to termination of employment with Employer and prior to his or her Security Release Date (as defined in Section 10 below), Employee's designated beneficiary shall be entitled to receive as a death benefit an amount equal to four times Employee's annual base salary at the time of death. The amount described in the preceding sentence shall be paid from the proceeds of the Policy. To the extent that the death benefit under the Policy exceeds such amount, the balance of the death benefit shall be payable to the Company. The designation of the beneficiaries under the Policy shall be in accordance with this Section.

(b) Employee agrees that, during the period of this Agreement, Employee will obtain and provide to the Company and/or the Insurance Company the written consent of the spouse of the Employee, in the form attached hereto as Exhibit B, to any designation by Employee of anyone other than the Employee's spouse as the beneficiary to receive the benefits under this Section 4.

5. Employee's attaining his or her Security Release Date or termination of Employee's employment on account of a Qualifying Termination.

(a) By making timely payment of the premiums described in Section 3, the Company may renew its Security Interest in the Policy for the period commencing with the due date of such payment until the later of (1) the due date of the next payment described in Section 3, or (2) the date that Employee attains his or her Security Release Date or terminates employment with the Employer on account of a Qualifying Termination (either of which events described in this clause 2 is referred to herein as a "Qualifying Event"). The Company may not extend its Security Interest in the Policy under the Collateral Security Assignment Agreement attached as Exhibit A after the occurrence of a Qualifying Event. After such Qualifying Event, Employee shall be entitled to exercise all of his or her ownership rights in the Policy without any limitation, and this Agreement and its accompanying Collateral Security Assignment Agreement shall no longer constitute a restriction on Employee's rights.

(b) Notwithstanding paragraph (a), the Company shall continue to have its Security Interest in the Policy to the extent required to satisfy its withholding obligations as described in Section 12.

6. Termination of an Employee for a reason other than a Qualifying Termination.

If the employment of Employee with Employer is terminated prior to his or her Security Release Date for a reason other than a Qualifying Termination (as described below), Employee shall cause, either by withdrawing from or borrowing against the Policy, on a nonrecourse basis, to be transferred to the Company an amount equal to the maximum amount that may then be obtained under the Policy. In the event that the amount that can be withdrawn from or borrowed against the Policy is less than the cash surrender value of the Policy, the Company shall withhold from other compensation payable to Employee the amount of such difference unless Employee has previously transferred to the Company an amount equal to such difference. In no event shall Employee's voluntary resignation prior to attaining his or her Security Release Date (as such concept is further defined below) ever constitute a Qualifying Termination, except in certain situations following a Change in Control (see Section 9).

7. Definition of a Qualifying Termination.

A Qualifying Termination is either of the following events: the termination of Employee by Employer for any reason other than "Cause," as described in Section 8; or the termination of Employee after a Change in Control under the circumstances described in Section 9(a). Both of these concepts are further defined below.

8. Qualifying Termination because Employee is terminated for a reason other than "Cause".

For purposes of this Section, "Cause" shall mean (1) Employee's failure to render services to the Employer where such failure amounts to gross neglect or misconduct of Employee's responsibilities and duties; (2) Employee's commission of an act of fraud or dishonesty against the Employer; or (3) Employee's conviction of a felony or other crime involving moral turpitude.

9. Qualifying Termination on account of termination after a Change in Control.

(a) A Qualifying Termination shall be treated as occurring after a "Change in Control" (as defined below) if there is first a "Change in Control" and then, within one year following such Change in Control, either (1) Employee's employment with the Employer is terminated without "Cause" (as defined in Section 8) or (2) Employee terminates his or her employment with the Employer for "Good Reason" (as defined in subsection (c) below).

(b) For purposes of this Section, a "Change in Control" shall mean the occurrence of any of the following:

(1) 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 defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Company representing 20% or more of the combined power of the Company's then outstanding securities, excluding any employee benefit plan sponsored or maintained by the Company (or any trustee of such plan acting as trustee);

(2) the stockholders of the Company approve an agreement to merge or consolidate the Company with another corporation (other than a corporation 50% or more of which is controlled by, or is under common control with, the Company);

(3) any individual who is nominated by the Board of Directors of the Company for election to the Board of Directors of the Company 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 of Directors;

(4) a change in control of the Company 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; or

(5) a majority of the Board of Directors of the Company determines in its sole and absolute discretion that there has been a Change in Control

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

Notwithstanding Paragraphs (1) through (4) of this Section 9(b), a Change in Control shall not occur by reason of any event which would otherwise constitute a Change in Control if, immediately after the occurrence of such event, individuals who are Acquiring Persons and who were employees of the Company immediately prior to the occurrence of such event own, on a fully diluted basis, securities of the Company representing (a) 5% or more of the combined voting power of the Company's then outstanding equity securities or (b) 5% or more of the value of the Company's then outstanding equity securities.

(c) For purposes of this Section, "Good Reason" shall mean the occurrence of one of the following events:

(1) the assignment to the Employee of any duties inconsistent with, or the reduction of powers or functions associated with, his positions, duties, responsibilities and status with the Employer immediately prior to a Change in Control, or any removal of the Employee from, or any failure to reelect the Employee to, any positions or offices the Employee held immediately prior to a Change in Control, except in connection with the termination of the Employee's employment by the Employer for "Cause" (as defined in Section 8);

(2) a reduction by the Employer of the Employee's base salary as in effect immediately prior to a Change in Control, except in connection with the termination of the Employee's employment by the Employer for "Cause" (as defined in Section 8);

(3) a change in the Employee's principal work location to a location more than forty (40) miles from Fayetteville, Arkansas, except for required travel on the Employer's business to an extent substantially consistent with the Employee's business travel obligations immediately prior to a Change in Control;

(4) (A) the failure by the Employer to continue in effect any employee benefit plan, program or arrangement (including, without limitation, "employee benefit plans" within the meaning of Section 3(3) of the Employee Retirement Income Security Act of 1974) in which the Employee was participating immediately prior to a Change in Control (or substitute plans, programs or arrangements providing the Employee with substantially similar benefits), (B) the taking of any action, or the failure to take any action, by the Employer which could (i) adversely affect the Employee's participation in, or materially reduce the Employee's benefits under, any of such plans, programs or

arrangements, (ii) materially adversely affect the basis for computing benefits under any of such plans, programs or arrangements or (iii) deprive the Employee of any material fringe benefit enjoyed by the Employee immediately prior to a Change in Control or (C) the failure by the Employer to provide the Employee with the number of paid vacation days to which the Employee was entitled immediately prior to a Change in Control in accordance with the Employer's vacation policy applicable to the Employee then in effect, except in connection with the termination of the Employee's employment by the Company for "Cause" (as defined in Section 8);

(5) the failure by the Employer to pay the Employee any portion of the Employee's current compensation, or any portion of the Employee's compensation deferred under any plan, agreement or arrangement of or with the Employer within seven (7) days of the date such compensation is due;

(6) a material increase in the required working hours of the Employee from that required prior to a Change in Control; or

(7) the failure by the Employer to obtain an assumption of the obligations of the Employer under this Agreement by any successor to the Employer.

(d) A termination of employment by Employee within the 12-month period following a Change in Control shall be for Good Reason if one of the occurrences specified in paragraph (c) shall have occurred, notwithstanding that Employee may have other reasons for terminating employment, including employment by another employer which Employee desires to accept.

10. Employee's attaining his or her Security Release Date.

(a) Employee's "Security Release Date" shall mean the date which is at least two years following the date on which the Company receives from Employee a completed notice in the form attached hereto as Exhibit C, provided that Employee continues to be employed by Employer until such date. Employee's election of a Security Release Date shall be irrevocable.

(b) Employee's "Security Release Date" shall also mean the one-year anniversary of a Change in Control, provided that Employee continues to be employed by Employer until such date.

(c) Employee shall attain his or her Security Release Date upon becoming disabled while employed by the Employer. Employee shall be considered "disabled" at the time that the Administrator (as defined in Section 13(a) below) determines, based upon competent medical advice, that an Employee is incapable of rendering substantial services to the Employer by reason of mental or physical disability.

(d) The Company's Security Interest in the Policy is contingent upon the timely payment of the premiums required under Section 3 of this Agreement. Each period covered by any individual premium payment shall be considered an independent extension of the Company's Security Interest in the Policy. In the event that the Company waives its rights by reason of failure to make payments under Section 3 of this Agreement, Employee shall immediately attain his or her Security Release Date (provided, however, that the cessation of the Company's obligations to pay premiums upon Employee's filing of an election of a Security Release Date shall not result in Employee immediately attaining his or her Security Release Date.) The Company's failure to extend its rights in no way affects the Company's duties and obligations under this Agreement.

11. Limitation on Employee's rights prior to a Qualifying Event.

In order to protect the Company's Security Interest and notwithstanding any other provisions in this Agreement, prior to a Qualifying Event, Employee agrees that he or she will not modify the death benefit under the Policy, direct the investment of the cash surrender value of the Policy, borrow against the Policy, assign the Policy, or obtain any portion of the cash value of the Policy. Notwithstanding the preceding sentence, if Section 6 applies to a termination, Employee may borrow or withdraw from the Policy, so long as the borrowing or withdrawal request is submitted to the Insurance Company along with a directive that the borrowed or withdrawn amount be transferred directly to the Company. Prior to the release of the Company's Security Interest in the Policy, Employee and the Company agree that the Company shall from time to time appoint one or more individuals (the "Designee"), who may be officers of the Company, who shall be entitled to direct the investments under the Policy; provided, however, that, the Designee may only direct the investments under the Policy in funds offered by the Insurance Company under the Policy.

12. Tax Withholding.

It is recognized by the parties that the rights of Employee in the Policy (as modified by the Agreement) may cause Employee to be treated under certain circumstances as in receipt of gross income. These circumstances may also impose upon the Company an obligation to deduct and withhold federal, state or local taxes. Unless Employee otherwise provides the Company the amounts it is required to withhold, Employee shall cause, either by withdrawing from or borrowing on a nonrecourse basis against the Policy, to be transferred to the Company that portion of the cash value of the Policy which is equal to the amount of any federal, state or local taxes required to be withheld.

13. Disputes.

(a) The Compensation Committee of the Board of Directors of the Company (the "Administrator") shall administer this Agreement. The Administrator (either directly or through its designees) will have power and authority to interpret, construe, and administer this Agreement (for the purpose of this section, the Agreement shall include the Collateral Security Assignment Agreement); provided that, the Administrator's authority to interpret this Agreement shall not cause the Administrator's decisions in this regard to be entitled to a deferential standard of review in the event that Employee or his or her beneficiary seeks review of the Administrator's decision as described below.

(b) Neither the Administrator, its designee nor its advisors, shall be liable to any person for any action taken or omitted in connection with the interpretation and administration of this Agreement.

(c) Because it is agreed that time will be of the essence in determining whether any payments are due to Employee or his or her beneficiary under this Agreement, Employee or his or her beneficiary may, if he or she desires, submit any claim for payment under this Agreement or dispute regarding the interpretation of this Agreement to arbitration. This right to select arbitration shall be solely that of Employee or his or her beneficiary and Employee or his or her beneficiary may decide whether or not to arbitrate in his or her discretion. The "right to select arbitration" is not mandatory on Employee or his or her beneficiary and Employee or his or her beneficiary may choose in lieu thereof to bring an action in an appropriate civil court. Once an arbitration is commenced, however, it may not be discontinued without the mutual consent of both parties to the arbitration. During the lifetime of the Employee only he or she can use the arbitration procedure set forth in this section.

(d) Any claim for arbitration may be submitted as follows: if Employee or his or her beneficiary disagrees with the Administrator regarding the interpretation of this Agreement and the claim is finally denied by the Administrator in whole or in part, such claim may be filed in writing with an arbitrator of Employee's or beneficiary's choice who is selected by the method described in the next four sentences. The first step of the selection shall consist of Employee or his or her beneficiary submitting a list of five potential arbitrators to the Administrator. Each of the five arbitrators must be either (1) a member of the National Academy of Arbitrators located in the State of Arkansas or (2) a retired Arkansas Circuit Court, Court of Appeals or Supreme Court judge. Within one week after receipt of the list, the Administrator shall select one of the five arbitrators as the arbitrator for the dispute in question. If the Administrator fails to select an arbitrator in a timely manner, Employee or his or her beneficiary shall then designate one of the five arbitrators as the arbitrator for the dispute in question.

(e) The arbitration hearing shall be held within seven days (or as soon thereafter as possible) after the picking of the arbitrator. No continuance of said hearing shall be allowed without the mutual consent of Employee or his or her beneficiary and the

Administrator. Absence from or nonparticipation at the hearing by either party shall not prevent the issuance of an award. Hearing procedures which will expedite the hearing may be ordered at the arbitrator's discretion, and the arbitrator may close the hearing in his or her sole discretion when he or she decides he or she has heard sufficient evidence to satisfy issuance of an award.

(f) The arbitrator's award shall be rendered as expeditiously as possible and in no event later than one week after the close of the hearing. In the event the arbitrator finds that the Company has breached this Agreement, he or she shall order the Company to immediately take the necessary steps to remedy the breach. The award of the arbitrator shall be final and binding upon the parties. The award may be enforced in any appropriate court as soon as possible after its rendition. If an action is brought to confirm the award, both the Company and Employee agree that no appeal shall be taken by either party from any decision rendered in such action.

(g) Solely for purposes of determining the allocation of the costs described in this subsection, the Administrator will be considered the prevailing party in a dispute if the arbitrator determines (1) that the Company has not breached this Agreement and (2) the claim by Employee or his or her beneficiary was not made in good faith. Otherwise, Employee or his or her beneficiary will be considered the prevailing party. In the event that the Company is the prevailing party, the fee of the arbitrator and all necessary expenses of the hearing (excluding any attorneys' fees incurred by the Company) including stenographic reporter, if employed, shall be paid by the other party. In the event that Employee or his or her beneficiary is the prevailing party, the fee of the arbitrator and all necessary expenses of the hearing (including all attorneys' fees incurred by Employee or his or her beneficiary in pursuing his or her claim), including the fees of a stenographic reporter if employed, shall be paid by the Company.

14. Collateral Security Assignment of Policy to the Company.

In consideration of the promises contained herein, the Employee has contemporaneously herewith granted the Security Interest in the Policy to the Company as collateral, under the form of Collateral Security Assignment attached hereto as Exhibit A, which Collateral Security Assignment gives the Company the limited power to enforce its rights to recover the cash value of the Policy, or a portion of the death benefit thereof, under the circumstances defined herein. The Company's Security Interest in the Policy shall be specifically limited to the rights set forth above in this Agreement, notwithstanding the provisions of any other documents including the Policy. Employee agrees to execute any notice prepared by the Company requesting a withdrawal or non-recourse loan in an amount equal to the amount to which the Company is entitled under Sections 5, 6 or 12 of this Agreement.

15. Employee's beneficiary rights and security interest.

(a) The Company and Employee intend that in no event shall the Company have any power or interest related to the Policy or its proceeds, except as provided herein and in the Collateral Security Assignment. In the event that the Company ever receives or may be deemed to have received any right or interest in the Policy or its proceeds beyond the limited rights described herein and in the Collateral Security Assignment, such right or interest shall be held in trust for the benefit of Employee and be held separate from the property of the Company. The Company hereby agrees to act as trustee for the benefit of Employee concerning any right to the Policy or its proceeds, except to the extent expressly provided otherwise in this Agreement.

(b) In order to further protect the rights of the Employee, the Company agrees that its rights to the Policy and proceeds thereof shall serve as security for the Company's obligations as provided in this Agreement to Employee. The Company grants to Employee a security interest in and collaterally assigns to Employee any and all rights the Company has in the Policy, and products and proceeds thereof whether now existing or hereafter arising pursuant to the provisions of the Policy, this Agreement, the Collateral Security Assignment or otherwise, to secure any and all obligations owed by the Company to Employee under this Agreement. In no event shall this provision be interpreted to reduce Employee's rights to the Policy or expand in any way the rights or benefits of the Company under this Agreement, the Policy or the Collateral Security Assignment. This security interest granted to Employee from the Company shall automatically expire and be deemed waived if Employee terminates employment with Employer prior to a Qualifying Event. Nothing in this provision shall prevent the Company from receiving its share of the death benefits under the Policy as provided in Section 4 of this Agreement.

16. Amendment of Agreement.

Except as provided in a written instrument signed by the Company and Employee, this Agreement may not be cancelled, amended, altered, or modified.

17. Notice under Agreement.

Any notice, consent, or demand required or permitted to be given under the provisions of this Agreement by one party to another shall be in writing, signed by the party giving or making it, and may be given either by delivering it to such other party personally or by mailing it, by United States Certified mail, postage prepaid, to such party, addressed to its last known address as shown on the records of the Company. The date of such mailing shall be deemed the date of such mailed notice, consent, or demand.

18. Binding Agreement.

This Agreement shall bind the parties hereto and their respective successors, heirs, executor, administrators, and transferees, and any Policy beneficiary.

19. Controlling law and characterization of Agreement.

(a) To the extent not governed by federal law, this Agreement and the right to the parties hereunder shall be controlled by the laws of the State of Arkansas.

(b) If this Agreement is considered a "plan" under the Employee Retirement Income Security Act of 1974 (ERISA), both the Company and Employee acknowledge and agree that for all purposes the Agreement shall be treated as a "welfare plan" within the meaning of Section 3(1) of ERISA, so that only those provisions of ERISA applicable to welfare plans shall apply to the Agreement, and that any rights that might arise under ERISA if this Agreement were treated as a "pension plan" within the meaning of Section 3(2) of ERISA are hereby expressly waived. Consistent with the preceding sentence, Employee further acknowledges that his or her rights to the Policy and the release of the Company's Security Interest are strictly limited to those rights set forth in this Agreement. In furtherance of this acknowledgement and in consideration of the Company's payment of the initial premiums for this Policy, Employee voluntarily and irrevocably relinquishes and waives any additional rights in the Policy or any different restrictions on the release of the Company's Security Interest that he or she might otherwise argue to exist under either state, federal, or other law. Employee further agrees that he or she will not argue that any such additional rights or different restrictions exist in any judicial or arbitration proceeding. Similarly, the Company acknowledges that its Security Interest is strictly limited as set forth in this Agreement and voluntarily and irrevocably relinquishes and waives any additional interests or different interests or advantages that the Company would have or enjoy if the Agreement were not treated as a "welfare plan" within the meaning of section 3(1) of ERISA.

20. Execution of Documents.

The Company and Employee agree to execute any and all documents necessary to effectuate the terms of this Agreement.

SOUTHWESTERN ENERGY COMPANY

By: /s/ CHARLES E. SCHARLAU

Its: Chairman and CEO

EMPLOYEE

/s/ STANLEY D. GREEN

EXHIBIT A

COLLATERAL SECURITY ASSIGNMENT AGREEMENT

This Collateral Security Assignment is made and entered into effective as of February 1, 1996, by the undersigned as the owner (the "Owner") of Life Insurance Policy Number 1A23067760 (the "Policy") issued by Pacific Mutual Life Insurance Company (the "Insurer") upon the life of Owner and by Southwestern Energy Company, an Arkansas corporation (the "Assignee").

WHEREAS, the Owner is a valued employee of Assignee or a subsidiary of Assignee, and the Assignee wishes to retain him or her in its or its subsidiary's employ; and

WHEREAS, as an inducement to the Owner's continued employment, the Assignee wishes to pay premiums on the Policy, as more specifically provided for in that certain Split- Dollar Life Insurance Agreement dated as of February 1, 1996, and entered into between the Owner and the Assignee as such agreement may be hereafter amended or modified (the "Agreement") (unless otherwise indicated the terms herein shall have the definitions ascribed thereto in the Agreement);

WHEREAS, in consideration of the Assignee agreeing to make the premium payments, the Owner agrees to grant the Assignee a security interest in the Policy as collateral security; and

WHEREAS, the Owner and Assignee intend that the Assignee have no greater interest in the Policy than that prescribed herein and in the Agreement and that if the Assignee ever obtains any right or interest in the Policy or the proceeds thereof, except as provided herein and in the Agreement, such right or interest shall be held in trust for the Owner to satisfy the obligations of Assignee to Owner under the Agreement and the Assignee additionally agrees that its rights to the Policy shall serve as security for its obligations to the Owner under the Agreement;

NOW, THEREFORE, the Owner hereby assigns, transfers and sets over to the Assignee for security the following specific rights in the Policy, subject to the following terms, agreements and conditions:

1. This Collateral Security Assignment is made, and the Policy is to be held, as collateral security for all liabilities of the Owner to the Assignee pursuant to the terms of the Agreement, whether now existing or hereafter arising (the "Secured Obligations"). The Secured Obligations include: (i) the obligation of the Owner to transfer an amount equal to the entire cash value in the event that the Owner terminates employment with Employer for a reason other than a Qualifying Termination and before attaining his or her Security Release Date; (ii) the obligation of the Owner to pay an amount of cash to the Assignee or transfer to the Assignee that portion of the cash value which is equal to any federal, state

or local taxes that Assignee may be required to withhold and collect (as set forth in Section 12 of the Agreement); and (iii) the obligation of the Owner to name the Assignee as beneficiary for a portion of the death benefit under the Policy in the event of the death of Owner prior to Owner's termination of employment with Employer in accordance with Section 4 of the Agreement.

2. The Owner hereby grants to Assignee a security interest in and collaterally assigns to Assignee the Policy and the cash value to secure the Secured Obligations. However, the Assignee's interest in the Policy shall be strictly limited to:

(a) The right to be paid the Assignee's portion of the death benefit in the event of the death of Owner prior to Owner's termination of employment with Employer in accordance with Section 4 of the Agreement;

(b) The right to receive an amount equal to the entire cash value of the Policy (which right may be realized by Assignee's receiving a portion of the death benefit under the Policy or by Owner's causing such amount to be transferred to Assignee (through withdrawing from or borrowing against the Policy) in accordance with the terms of the Agreement) if the Owner terminates employment with Employer for a reason other than a Qualifying Termination (unless he or she has previously attained his or her Security Release Date); and

(c) The right to receive an amount equal to any federal, state or local taxes that Assignee may be required to withhold and collect (as set forth in Section 12 of the Agreement).

3.(a) Owner shall retain all incidents of ownership in the Policy, and may exercise such incidents of ownership except as otherwise limited by the Agreement and hereunder. The Insurer is only authorized to recognize (and is fully protected in recognizing) the exercise of any ownership rights by Owner if the Insurer determines that the Assignee has been given notice of Owner's purported exercise of ownership rights in compliance with the provisions of Section 3(b) hereof and as of the date thirty days after such notice is given, the Insurer has not received written notification from the Assignee of Assignee's objection to such exercise; provided that, the designation of the beneficiary to receive the death benefits not otherwise payable to Assignee pursuant to Section 4 of the Agreement may be changed by the Owner without prior notification of Assignee. The Insurer shall not be responsible to ensure that the actions of the Owner conform to the Agreement.

(b) Assignee hereby acknowledges that for purposes of this Collateral Security Assignment, Assignee shall be conclusively deemed to have been properly notified of Owner's purported exercise of his or her ownership rights as of the third business day following either of the following events: (1) Owner mails written notice of such exercise to Assignee by United States certified mail, postage paid, at the address below and provides the Insurer with a copy of such notice and a copy of the certified mail receipt or (2) the

Insurer mails written notice of such exercise to Assignee by regular United States mail, postage paid, at the address set forth below:

Southwestern Energy Company P.O. Box 1408 Fayetteville, Arkansas 72702

ATTN: Corporate Secretary

The foregoing address shall be the appropriate address for such notices to be sent unless and until the receipt by both Owner and the Insurer of a written notice from Assignee of a change in such address.

(c) Notwithstanding the foregoing, Owner and Assignee hereby agree that, until Assignee's security interest in the Policy is released, Assignee shall from time to time designate one or more individuals (the "Designee"), who may be officers of Assignee, who shall be entitled to adjust the death benefit under the Policy and to direct the investments under the Policy; provided, however, that the Designee may only increase, but not decrease, the death benefit in effect on the date that the Policy is issued; provided, further, that the Designee may only direct the investments under the Policy in funds offered by the Insurer under the Policy. Assignee shall notify the Insurer in writing of the identity of the Designee and any changes in the identity of the Designee. Until Assignee's security interest in the Policy is released, no other party may adjust the death benefit or direct the investments under the Policy without the consent of the Assignee and Owner.

4. If the Policy is in the possession of the Assignee, the Assignee shall, upon request, forward the Policy to the Insurer without unreasonable delay for endorsement of any designation or change of beneficiary or the exercise of any other right reserved by the Owner.

5.(a) Assignee shall be entitled to exercise its rights under the Agreement by delivering a written notice to Insurer, executed by the Assignee and the Owner or the Owner's beneficiary, requesting either (1) a withdrawal or nonrecourse policy loan equal to the amount to which Assignee is entitled under Sections 5, 6 or 12 of the Agreement and transfer of such withdrawn or borrowed amount to Assignee or (2) the payment to the Assignee of that portion of the death benefit under the Policy to which the Assignee is entitled under Section 4 of the Agreement. So long as the notice is also signed by Owner or his or her beneficiary, Insurer shall pay or loan the specified amounts to Assignee without the need for any additional documentation.

(b) Upon receipt of a properly executed notice complying with the requirements of subsection (a) above, the Insurer is hereby authorized to recognize the Assignee's claims to rights hereunder without the need for any additional documentation and without investigating (1) the reason for such action taken by the Assignee; (2) the validity or the amount of any of the liabilities of the Owner to the Assignee under the Agreement; (3) the existence of any default therein; (4) the giving of any notice required herein; or (5) the application to be made by the Assignee of any amounts to be paid to the Assignee. The receipt of the Assignee for any sums received by it shall be a full discharge and release therefor to the Insurer.

6. Upon the full payment of the liabilities of the Owner to the Assignee pursuant to the Agreement, the Assignee shall execute an appropriate release of this Collateral Security Assignment.

7. The Assignee shall have the right to request of the Insurer and/or the Owner notice of any action taken with respect to the Policy by the Owner.

8.(a) The Assignee and the Owner intend that in no event shall the Assignee have any power or interest related to the Policy or its proceeds, except as provided herein and in the Agreement, notwithstanding the provisions of any other documents including the Policy. In the event that the Assignee ever receives or may be deemed to have received any right or interest beyond the limited rights described herein and in the Agreement, such right or interest shall be held in trust for the benefit of the Owner and be held separate from the property of the Assignee. The Assignee hereby agrees to act as trustee for the benefit of the Owner concerning any right to the Policy or its proceeds, except to the extent expressly provided otherwise in the Agreement and this Collateral Security Assignment Agreement.

(b) In order to further protect the rights of the Owner, the Assignee agrees that its rights to the Policy and proceeds thereof shall serve as security for the Assignee's obligations to the Owner as provided in the Agreement. Assignee hereby grants to Owner a security interest in and collaterally assigns to Owner any and all rights it has in the Policy, and products and proceeds thereof, whether now existing or hereafter arising pursuant to the provisions of the Policy, the Agreement, this Collateral Security Assignment or otherwise, to secure Assignee's obligations ("Assignee Obligations") to Owner under the Agreement, whether now existing or hereafter arising. The Assignee Obligations include all obligations owed by the Assignee to Owner under the Agreement, including without limitation: (i) the obligation to transfer ownership of the Policy to Owner and to make the premium payments required under Section 3 of the Agreement and (ii) the obligation to do nothing which may, in any way, endanger, defeat or impair any of the rights of Owner in the Policy as provided in the Agreement. In no event shall this provision be interpreted to reduce Owner's rights in the Policy or expand in any way the rights or benefits of the Assignee under the Agreement. In the event that Owner terminates employment with Employer for any reason prior to a Qualifying Event, this security interest and collateral assignment granted by Assignee to Owner shall automatically expire and be deemed waived. Nothing in this provision shall prevent the Assignee from receiving its share of the death benefits under the Policy as provided in Section 4 of the Agreement.

9. Assignee and Owner agree to execute any documents necessary to effectuate this Collateral Security Assignment pursuant to the provisions of the Agreement. All

disputes shall be settled as provided in Section 13 of the Agreement. The rights under this Collateral Security Assignment may be enforced pursuant to the terms of the Agreement.

IN WITNESS WHEREOF, the Owner and Assignee have executed this Collateral Security Assignment effective the day and year first above written.

Stanley D. Green, Owner

SOUTHWESTERN ENERGY COMPANY

By:_______________________________

Title:_____________________________

EXHIBIT B

SPOUSAL CONSENT TO DESIGNATION OF NONSPOUSAL BENEFICIARY

My spouse is Stanley D. Green. I hereby consent to the designation made by my spouse of ________________ as the beneficiary (subject to any rights collaterally assigned to Southwestern Energy Company) under Life Insurance Policy No. 1A23067760, which Southwestern Energy Company has purchased from Pacific Mutual Life Insurance Company and transferred to him/her. I understand that this consent is valid only with respect to the naming of the beneficiary indicated above and that the designation of any other beneficiary will not be valid unless I consent in writing to such designation.

This consent is being voluntarily given, and no undue influence or coercion has been exercised in connection with my consent to the designation made by my spouse of the beneficiary named above rather than myself as the beneficiary under the Split-Dollar Life Insurance Policy.

Spouse's Signature

Print Spouse's Name

Date

EXHIBIT C

SPLIT-DOLLAR LIFE INSURANCE
TWO YEAR SECURITY RELEASE NOTICE

Pursuant to the Split-Dollar Life Insurance Agreement entered into between Southwestern Energy Company (the "Company") and me dated as of February 1, 1996 (the "Agreement"), I hereby notify the Company that I request to be released on _____, _____ ("Security Release Date") from the Company's collateral security in Policy Number 1A23067760 issued by Pacific Mutual Life Insurance Company. I understand that my Security Release Date must be at least two years from the date on which the Company receives this Notice. I further understand that in order for the Company's collateral security interest to be released on my Security Release Date, I must continue to be employed by the Company or one of its subsidiaries (as defined in the Agreement) until such date.

Stanley D. Green

Date

Received by Southwestern Energy Company

on ____

By ____

RESULTS OF OPERATIONS

Net income in 1995 was $11.2 million, or $.45 per share, down from $25.1 million, or $.98 per share, in 1994. Net income in 1993 was $27.1 million, or $1.05 per share. Net income in 1995 includes an extraordinary loss (net of tax benefit) of $.3 million, or $.01 per share, incurred in connection with the early call of the Company's 10.63% Senior Notes due September 30, 2001. The comparative 1993 number excludes the cumulative effect of a change in accounting for income taxes which was recorded in the first quarter of 1993. Operating results for 1993 also included an adjustment of $1.7 million, or $.07 per share, to decrease net income and record the effect on accumulated deferred income taxes of a legislated increase in the federal corporate income tax rate. There were no accounting changes or extraordinary items recorded in 1994.

The decline in 1995 earnings was caused primarily by the generally low level of gas prices and a decline in natural gas production. The decrease in 1994 earnings, as compared to 1993, resulted as lower gas prices and much warmer weather offset the favorable effect of a year-to-year increase in natural gas production. Lower gas prices in 1995 and 1994 reflected both the general decline in spot market prices and the effect of a settlement approved by the Arkansas Public Service Commission (APSC) to resolve a dispute concerning the Company's pricing of intersegment sales (the Gas Cost Settlement). The Gas Cost Settlement, which was effective July 1, 1994, increased the volumes which could be sold by the Company's exploration and production segment to its gas distribution segment, but made the sales price equal to a spot market index plus a premium. The index-based pricing has to date resulted in a lower intersegment sales price. The Gas Cost Settlement and the increases in recent years in sales of gas production to unaffiliated purchasers have both caused earnings to become more sensitive to changes in the market price for natural gas. Revenues and operating income for the Company's major business segments are shown in the following table.

	1995	1994	1993
		(in thousands)	
REVENUES			
Exploration and production	$ 63,523	$ 80,123	$ 79,374
Gas distribution	119,855	127,060	131,892
Other	336	308	262
Eliminations	(30,603)	(37,305)	(36,684)
	$153,111	$170,186	$174,844
OPERATING INCOME			
Exploration and production	$ 20,523	$ 38,888	$ 42,608
Gas distribution	11,133	13,386	15,261
Corporate expenses	(468)	(192)	(305)
	$ 31,188	$ 52,082	$ 57,564

EXPLORATION AND PRODUCTION REVENUES

The Company's exploration and production revenues decreased 21% in 1995 and increased 1% in 1994. The decrease in 1995 was due to lower average gas prices and a decline in the Company's offshore gas production. The slight increase in 1994 was due to increases in natural gas and oil production, offset by lower average prices.

Gas production decreased 8% to 34.5 billion cubic feet (Bcf) in 1995 from 37.7 Bcf in 1994. Gas production in 1994 increased by 6% from 35.7 Bcf in 1993. Sales from the Company's offshore properties were 2.7 Bcf in 1995, compared to 5.6 Bcf in 1994 and 6.3 Bcf in 1993. Sales in 1994 were helped by the start of production from a new offshore platform which was completed late in 1993. Sales from the Company's onshore production were 31.8 Bcf in 1995, down slightly from 32.1 Bcf in 1994. Sales from onshore production were 29.4 Bcf in 1993. Production from producing properties acquired in 1994 and 1995 largely offset declines in production from the Company's other onshore properties during 1995, including an unexpected decline from the Earl Chauvin No. 1 well, a 1993 discovery in southeast Louisiana.

	1995	1994	1993
GAS PRODUCTION			
Affiliated sales (Bcf)	13.9	13.9	12.8
Unaffiliated sales (Bcf)	20.6	23.8	22.9
	34.5	37.7	35.7
Average price per Mcf	$1.72	$2.04	$2.18
OIL PRODUCTION			
Unaffiliated sales (MBbls)	229	200	97
Average price per Bbl	$17.15	$15.89	$17.20

Gas sales to unaffiliated purchasers were 20.6 Bcf in 1995, down from 23.8 Bcf in 1994. Gas sales to unaffiliated purchasers were 22.9 Bcf in 1993. The decrease in 1995 sales to unaffiliated purchasers was primarily the result of decreased production from the Company's Gulf Coast properties, as discussed above. Sales to unaffiliated purchasers are made under contracts which reflect current short-term prices and which are subject to seasonal price swings. The Company uses natural gas price hedges on a limited basis to reduce the Company's exposure to the risk of changing prices.

Deliveries for injection into storage and the Gas Cost Settlement increased the demand of the Company's utility distribution systems for gas supply in 1995 and 1994, as compared to 1993. Intersegment sales to Arkansas Western Gas Company (AWG), the utility subsidiary which operates the Company's northwest Arkansas utility system, were 8.5 Bcf in 1995, 8.8 Bcf in 1994, and 7.1 Bcf in 1993. The Company's gas production provided approximately 65% of AWG's requirements in 1995, 64% in 1994, and approximately 57% in 1993. Additionally, in 1995, 1994, and 1993, the Company sold .6 Bcf, .5 Bcf, and .7 Bcf, respectively, of gas to AWG for its spot market purchasing program.

The Company's sales to AWG under the spot market purchasing program are based upon competitive bids and generally reflect current spot market prices. Most of the remaining sales to AWG's system are pursuant to a long-term contract entered into in 1978 and which was amended and restated in 1994 as a result of the Gas Cost Settlement, discussed more fully below under "Regulatory Matters." Other sales to AWG are made under long-term contracts with flexible pricing provisions.

The Company's intersegment sales to Associated Natural Gas Company (Associated), a division of AWG which operates the

Company's natural gas distribution systems in northeast Arkansas and parts of Missouri, were 5.4 Bcf in 1995, 5.1 Bcf in 1994, and 5.7 Bcf in 1993. Deliveries to Associated increased in 1995 due to colder weather in the heating season and decreased in 1994 due to warmer weather. Effective October, 1990, one of the Company's exploration and production subsidiaries entered into a ten-year contract with Associated to supply its base load system requirements at a price to be redetermined annually. The sales price under this contract was $1.90 per thousand cubic feet (Mcf) from inception of the contract through the first nine months of 1993, $2.385 per Mcf for the contract period ending September 30, 1994, $2.20 per Mcf for the contract period ending September 30, 1995, and is currently $1.785 per Mcf.

The overall average price received at the wellhead for the Company's gas production was $1.72 per Mcf in 1995, $2.04 per Mcf in 1994, and $2.18 per Mcf in 1993. The decline in the average price received since 1993 reflects declines in average annual spot market prices, an increase in the proportionate share of the Company's production sold at spot market prices and under long-term contracts with market-sensitive pricing, and the effect of the Gas Cost Settlement. Natural gas prices were higher at December 31, 1995, as compared to the prior year-end, primarily due to colder than normal weather experienced across the country. The colder weather continued into early 1996 and has had a positive impact on average prices received to-date in 1996, as compared to 1995. As described above, a significant portion of the Company's gas pro-duction is sold under long-term contracts to its gas distribution subsidiary. In the past, the fixed prices received under these sales arrangements helped reduce the effects of fluctuations in spot market prices for natural gas. Going forward, the Company expects increased volatility and seasonality in its operating results as the majority of its gas sales will be tied to spot market prices. In the future, the Company expects the overall average price it receives for its total production to be generally higher than average spot market prices due to the premiums over spot which it receives under the long-term contracts covering its intersegment sales. Future changes in revenues from sales of the Company's 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.

The Company expects future increases in its gas production to come primarily from sales to unaffiliated purchasers. While the Company experienced a decline in gas production in 1995, it does expect over the long term to return to a trend of increasing gas production. However, the Company is unable to predict changes in the market demand and price for natural gas, including changes which may be induced by the effects of weather on demand of both affiliated and unaffiliated customers for the Company's production. Additionally, the Company holds a large block of undeveloped leasehold acreage and producing acreage which will continue to be developed in the future. The Company's exploration programs have been directed almost exclusively toward natural gas in recent years. The Company will continue to concentrate on developing and acquiring gas reserves, but will also selectively seek opportunities to participate in projects oriented toward oil production.

GAS DISTRIBUTION REVENUES

Gas distribution revenues fluctuate due to the pass-through of cost of gas increases and decreases, and due to the effects of weather. 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.

	1995	1994	1993
GAS DISTRIBUTION SYSTEMS			
Throughput (Bcf)			
Sales volumes	27.4	26.3	26.8
Transportation volumes			
End-use	5.2	4.8	5.6
Off-system	9.8	10.7	11.7
	42.4	41.8	44.1
Average number of sales customers	164,672	159,897	155,944
Heating weather--degree days	4,376	4,161	4,929
Average sales rate per Mcf	$4.12	$4.57	$4.65

Gas distribution revenues decreased by 6% in 1995 and by 4% in 1994. The decrease in 1995 resulted from lower purchased gas costs caused in part by the Gas Cost Settlement, which more than offset the effects of strong customer growth and weather which was 5% colder than the prior year. The decrease in 1994 was due to lower purchased gas costs and weather which was 16% warmer than in 1993, partially offset by customer growth.

In 1995, AWG sold 17.1 Bcf to its customers at an average rate of $3.93 per Mcf, compared to 16.3 Bcf at $4.25 per Mcf in 1994 and 17.1 Bcf at $4.40 per Mcf in 1993. Additionally, AWG transported 4.3 Bcf in 1995, 4.0 Bcf in 1994, and 3.9 Bcf in 1993 for its end-use customers. Associated sold 10.3 Bcf to its customers in 1995 at an average rate of $4.45 per Mcf, compared to 10.0 Bcf in 1994 at $5.10 per Mcf and 9.7 Bcf at $5.08 per Mcf in 1993. Associated transported .9 Bcf for its end-use customers in 1995, compared to .8 Bcf in 1994 and 1.7 Bcf in 1993. The increase in volumes sold and transported in 1995 for both AWG and Associated resulted from colder weather and from increases in the average number of customers. The decrease in the average sales rate since 1993 for AWG and the decrease in 1995 for Associated reflect the decline in the average cost of gas purchased for delivery to the Company's customers.

Total deliveries to industrial customers of AWG and Associated, including transportation volumes, increased to 13.0 Bcf in 1995, from 12.3 Bcf in 1994 and 11.7 Bcf in 1993. The steady increase reflects both the success of the Company's industrial marketing efforts and the continued economic strength of its service territory.

AWG also transported 9.8 Bcf of gas through its gatheringsystem in 1995 for off-system deliveries, all to the NOARK Pipeline System (NOARK), compared to 10.7 Bcf in 1994 and 11.7 Bcf in 1993. The average transportation rate was approximately $.13 per Mcf, exclusive of fuel, in all years.

Gas distribution revenues in future years will be impacted by both customer growth and rate increases allowed by regulatory commissions. In recent years, AWG has experienced customer growth of approximately 3.5% to 4.0% annually, while Associated has experienced customer growth of approximately 1% annually. Based on current economic conditions in the Company's service territories, the Company expects this trend in customer growth to continue. AWG filed an application with the APSC on January 30, 1996, for a rate increase of $7.2 million annually. The APSC has ten months in which to reach a decision on the amount of the rate increase to be approved. As a result, any increase granted will likely not become effective until late 1996. The Company anticipates filing a rate increase request for Associated's operations in late 1996. Rate increase requests which may be filed in the future will depend on customer growth, increases in operating expenses, and additional investments in property, plant and equipment.

REGULATORY MATTERS

During 1994, the Company entered into the Gas Cost Settlement with the Staff of the APSC and the Office of the Attorney General of the State of Arkansas concerning certain issues that had been outstanding before the APSC for the previous four years. These gas cost issues were first raised by the APSC in December, 1990, in connection with its approval of an AWG rate increase. The issues involved the price of gas sold under a long-term contract between AWG and one of the Company's gas producing subsidiaries. The terms of the Gas Cost Settlement became effective as of July 1, 1994, and were approved by the APSC on January 5, 1995. Under the Gas Cost Settlement, the price paid by AWG is tied to a monthly spot market index plus a premium. Given current market conditions, the new pricing provision results in a reduced sales price. That effect is offset in part by provisions of the Gas Cost Settlement which allow additional volumes to be sold under the amended contract. The amended contract provides for volumes equal to the historical level of sales under the contract to be sold at the spot market index plus a pre-mium of $.95 per Mcf, while incremental sales volumes receive a premium of $.50 per Mcf. In 1995, approximately 7.7 Bcf (net to the Company's interest) was sold under the contract, compared to approximately 8.1 Bcf and 6.0 Bcf in 1994 and 1993, respectively. Other significant terms of the Gas Cost Settlement preclude the parties thereto from asking for refunds, transfer certain of AWG's natural gas storage facilities to another subsidiary of the Company, and precluded AWG from filing an application for a rate increase for its northwest Arkansas system before January, 1996.

Associated received an order on July 14, 1995, from the Missouri Public Service Commission (MPSC) disallowing the recovery of approximately $2.0 million of gas costs, the result of gas cost audits covering the five-year period ending August 31, 1993. Of the total disallowed, $1.5 million represented a portion of the difference between the price paid by Associated under its long-term firm contract with one of the Company's gas producing subsidiaries (described above under "Exploration and Production Revenues") and a spot market index price for gas delivered into an interstate pipeline operating in the Arkoma Basin. The balance of $.5 million disallowed represented take-or-pay charges passed through to Associated by its interstate suppliers and allocable to transportation customers of Associated. These take-or-pay charges resulted from pipeline deregulation pursuant to Order No. 636 of the Federal Energy Regulatory Commission, issued in April, 1992, which is a comprehensive set of regulations designed to encourage compe-tition and continue the significant restructuring of the interstate natural gas pipeline industry. Prior to Order No. 636, Associated purchased portions of its gas supply from interstate pipelines under firm long-term supply contracts. The APSC had previously reviewed the costs charged to Arkansas ratepayers under this contract and found them to be proper and allowable for recovery. Associated has appealed the MPSC's decision to the Circuit Court of Cole County, Missouri, and that court has stayed the MPSC's order and has directed Associated to pay the money to be refunded under the MPSC's order into the registry of the court while the appeal is pending. The MPSC Staff has also recommended the disallowance of an additional $.7 million of gas costs as a result of an audit for the year ended August, 1994. The MPSC has not yet issued an order in connection with that recommendation. The Company does not expect the ultimate outcome of these matters to have a material adverse impact on the results of operations or the financial position of the Company.

AWG also purchases gas from unaffiliated producers under take-or-pay contracts. Currently, the Company believes that it does not have a significant exposure to liabilities resulting from these contracts, although such exposure has increased in recent years as a result of a decline in its gas purchase requirements which has occurred as some of its large business customers converted to a transportation service offered by AWG and began to obtain their own gas supplies directly from other sources. The Company expects to be able to continue to satisfactorily manage its exposure to take-or-pay liabilities.

OPERATING COSTS AND EXPENSES

The Company's operating costs and expenses increased by 3% in 1995 and by 1% in 1994. The increase in 1995 was due primarily to increased purchased gas costs related to increased utility deliveries, increased general and administrative expenses, and increased production costs. General and administrative expenses increased due to inflationary increases in payroll and other costs and from personnel additions in the Company's exploration and production segment. Increased production costs in the exploration and production segment are related to workovers of producing wells and higher operating costs associated with the Company's expansion into areas outside of Arkansas. The slight increase in 1994 resulted from increased depreciation, depletion and amortization expense (DD&A), primarily related to the Company's exploration and production segment, and increased utility operating expenses, offset by lower purchased gas costs related to lower prices paid for gas supplies. Purchased gas costs are one of the largest expense items in each year, typically representing 30% to 40% of the Company's total operating costs and expenses. Purchased gas costs are influenced primarily by changes in requirements for gas sales of the gas distribution segment, the price and mix of gas purchased, and the timing of recoveries of deferred purchased gas costs.

The Company follows the full cost method of accounting for the exploration, development, and acquisition of oil and gas properties. DD&A is calculated using the units-of-production method. The Company's annual gas and oil production, as well as the amount of proved reserves owned by the Company and the costs associated with adding those reserves, are all components of the amortization calculation. DD&A for the exploration and production segment in 1995 decreased slightly from 1994 as an increase in the amortization rate per unit was offset by a decline in total units produced. DD&A increased 15% in 1994 due both to an increase in units produced and an increase in the amortization rate per unit. The margin between the Company's full cost ceiling and the financial statement carrying value of the Company's gas and oil properties was slightly higher at December 31, 1995, as compared to December 31, 1994, due primarily to a higher level of market prices for gas at year-end 1995. The margin was eroded substantially during 1994 as a result of very low average gas prices in effect at December 31, 1994. Market prices, production rates, levels of reserves, and the evaluation of costs excluded from amortization all influence the calculation of the full cost ceiling. A 15% to 20% decline in gas prices from year-end 1995 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a noncash charge against earnings.

Delays inherent in the rate-making process prevent the Company from obtaining immediate recovery of increased operating costs of its gas distribution segment. Inflation impacts the Company by generally increasing its operating costs and the costs of its capital additions. In recent years the impacts of inflation have been mitigated by conditions in the industries in which the Company operates. While some of the gas distribution subsidiary's gas purchase contracts include inflation-based price escalations, these clauses have generally not been operating as gas market conditions have led producers to accept prices below the contract maximum price. Continuing depressed conditions in the gas and oil industry have resulted in lower costs of drilling and leasehold acquisition.

OTHER COSTS AND EXPENSES

Interest costs were up 26% in 1995, as compared to 1994, due to both an increase in long-term debt and higher average interest rates. The increase in long-term debt is discussed below in "Liquidity and Capital Resources." Interest capitalized increased by 54% in 1995 due primarily to higher capital expenditures in the exploration and production segment where interest is capitalized on costs excluded from amortization. Interest costs were slightly lower in 1994, as compared to 1993, due to lower average borrowings on the Company's revolving credit facilities through most of the year, partially offset by higher average interest rates.

The change in other income in 1995, as compared to 1994, relates to a decrease in the Company's share of operating losses incurred by NOARK, partially offset by accruals for potential liabilities relating to certain regulatory gas cost issues and other legal matters. The change in other income during 1994, as compared to 1993, relates primarily to the Company's share of operating losses incurred by NOARK. The Company, through a subsidiary, holds a 47.93% general partnership interest in NOARK and is the pipeline's operator (See Note 7 of the financial statements for additional discussion). NOARK became operational in late 1992 and extends across northern Arkansas, crossing three major interstate pipelines. NOARK has been operating below capacity and generating losses since it was placed in service. The Company's share of the pretax loss from operations for NOARK included in other income was $.7 million in 1995, $2.8 million in 1994, and $1.8 million in 1993. The 1995 pretax loss included $2.9 million of income for the Company's share of a $6.0 million settlement of contract issues with one of NOARK's transporters, as discussed below. Deliveries are currently being made by NOARK to portions of AWG's distribution system, to Associated, and to the interstate pipelines with which NOARK interconnects. In 1995, NOARK had an average daily throughput of 86 million cubic feet of gas per day (MMcfd), compared to 82 MMcfd in 1994 and 79 MMcfd in 1993. NOARK has a total transportation capacity of approximately 141 MMcfd. AWG has contracted for 41 MMcfd of firm capacity on NOARK under a ten-year transportation contract, with seven years remaining on its original term. The contract is renewable year-to-year until terminated by 180 days' notice. NOARK also had a five-year transportation contract with Vesta Energy Company (Vesta) covering the marketer's commitment for 50 MMcfd of firm transportation. The Company's exploration and production segment was supplying 25 MMcfd of the volumes transported by Vesta under that agreement. In late 1993, Vesta filed suit against NOARK, the Company, and certain of its affiliates, and, effective January 1, 1994, ceased transporting gas under its contract with NOARK. In late 1995, the suit was settled prior to going to trial. In exchange for a $6.0 million payment to NOARK, Vesta was released from its obligations under its firm transportation agreement and its contract with the Company's affiliates.

The APSC has established a maximum transportation rate of approximately $.285 per dekatherm for NOARK based on its original construction cost estimate of approximately $73 million. Due to construction conditions and the addition of a compressor station, the ultimate cost of the pipeline exceeded the original estimate by approximately $30 million. NOARK competes primarily with two interstate pipelines in its gathering area. One of those elected to become an open access transporter subsequent to NOARK's start of construction. The increased availability of interruptible transportation service has intensified the competitive environment within which NOARK operates. The Company expects further losses from its equity investment in NOARK until the pipeline is able to increase its level of throughput and until improvement occurs in the competitive conditions which determine the transportation rates NOARK can charge. The Company and the other partners of NOARK are currently investigating several options which would improve NOARK's future financial prospects. However, the

Company believes that no write-down of its investment in NOARK is appropriate at this time and that it will realize its investment in NOARK over the life of the system.

The Company's effective income tax rate was 38.6% in 1995, 38.5% in 1994, and 42.3% in 1993. The rate was higher in 1993 because the Company's deferred tax provision included $1.7 million of expense for the legislated increase in the maximum federal corporate income tax rate.

LIQUIDITY AND CAPITAL RESOURCES

The Company continues to depend principally on internally generated funds as its major source of liquidity. However, the Company has sufficient ability to borrow additional funds to meet its short-term seasonal needs for cash, to finance a portion of its routine spending, if necessary, or to finance other extraordinary investment opportunities which might arise. In 1995, 1994, and 1993, net cash provided from operating activities totaled $55.9 million, $66.6 million, and $70.2 million, respectively. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, and the provision for deferred income taxes. Net cash from operating activities provided 59% of the Company's capital requirements for routine capital expenditures, cash dividends, and scheduled debt retirements in 1995, 92% in 1994, and in excess of 100% in 1993.

Dividends paid to common shareholders in 1995 were $6.0 million, compared to $6.2 million in 1994 and $5.7 million in 1993. In July, 1993, the Board of Directors increased the quarterly dividend on the Company's common stock by 20% to $.06 per share from $.05 per share.

In February, 1995, the Board of Directors authorized the repurchase of up to $30.0 million of the Company's common shares. The Company repurchased 1,000,000 shares during 1995 at an average cost of $14.26, using its revolving credit facilities to fund the share repurchase. Shares repurchased will be held in treasury and may be used for general corporate purposes, including issuance under option plans. The Company does not at present have definite plans to repurchase additional shares, but may purchase additional shares from time to time, depending on market conditions.

Changes in the Company's liquidity in future years are expected to be related primarily to changes in cash flow generated from its operations.

CAPITAL EXPENDITURES

Capital expenditures totaled $101.6 million in 1995, $76.9 million in 1994, and $59.2 million in 1993. In 1995 and 1994, expenditures for the exploration and production segment included $6.0 million and $13.9 million, respectively, for acquisitions of reserves in place.

	1995	1994	1993
		(in thousands)	
CAPITAL EXPENDITURES			
Exploration and production	$ 82,237	$55,449	$37,411
Gas distribution	18,523	17,577	19,892
Other	866	3,828	1,916
	$101,626	$76,854	$59,219

The Company generally intends to adjust its level of routine capital expenditures depending on the expected level of internally generated cash and the level of debt in its capital structure. The Company expects that its level of capital spending will be adequate to allow the Company to maintain its present markets, explore and develop existing gas and oil properties as well as generate new drilling prospects, and finance improvements necessary due to normal customer growth in its gas distribution segment.

Capital spending planned for 1996 totals $86.4 million, a decrease of 15% from 1995, consisting of $71.0 million for gas and oil exploration, $13.5 million for gas distribution system expenditures, and $1.9 million for general purposes. The gas and oil expenditures consist of $24.5 million for development drilling, including $14.5 million for the Company's Arkansas program, $20.0 million for producing property acquisitions, and a total of $12.4 million for exploratory drilling and seismic data acquisition.

FINANCING REQUIREMENTS

Two floating rate revolving credit facilities provide the Company access to $80.0 million of variable rate long-term capital. Borrowings outstanding under these credit facilities totaled $22.9 million at the end of 1995 and $52.3 million at the end of 1994.

In November, 1995, the Company filed a shelf registration statement with the Securities and Exchange Commission for the issuance of up to $250.0 million of senior unsecured debt securities. Effective December 1, 1995, the Company issued under the shelf registration statement $125.0 million of 6.70% Senior Notes due 2005. Proceeds from the issuance of these notes were used primarily to repay certain borrowings under the Company's revolving credit facilities. The facilities had been drawn on to prepay the Company's 10.63% Senior Notes, to repurchase 1,000,000 shares of the Company's common stock, as described above, and to fund the Company's capital spending program. Additional debt securities may be issued in the future under the shelf registration statement as circumstances dictate. The Company's public notes were rated BBB+ by Standard and Poor's and Baa2 by Moody's Investor Service.

The Company and an affiliate of the other general partner of NOARK are required to severally guarantee the availability of certain minimum cash balances to service NOARK's 9.7375% Senior Secured Notes. These notes are held by a major insurance company which also has a 20% limited partnership interest in NOARK. The notes had a balance of $56.7 million at December 31, 1995, with final maturity in 2009. NOARK also has an unsecured long-term revolving credit agreement with a group of banks which provides the partnership access to $30.0 million of additional funds. Amounts outstanding under this credit arrangement were $23.2 million at December 31, 1995, and $29.6 million at December 31, 1994. Amounts borrowed under the long-term revolving credit agreement are severally guaranteed by the Company and an affiliate of the other general partner. The Company's share of the several guarantee of the notes and the line of credit is 60%. In 1995, the Company advanced $5.0 million to NOARK to fund its share of debt service payments. The Company expects to advance $1.0 to $1.5 million to NOARK during 1996 in connection with its guarantees. The anticipated contributions in 1996 are less than the 1995 amount due to the receipt by NOARK of the $6.0 million settlement payment from Vesta in December, 1995, as discussed above. The cash received was used by NOARK to pay down its revolving credit facility. The credit facility will be used in 1996 to help fund NOARK's long-term debt service payments before additional partner advances are called for.

Under its existing debt agreements, the Company may not issue long-term debt in excess of 65% of its total capital and may not issue total debt in excess of 70% of its total capital. To issue additional long-term debt, the Company must also have, after giving effect to the debt to be issued, a ratio of earnings to fixed charges of at least 1.50 or higher. At the end of 1995, the capital structure consisted of 51.6% debt (excluding the current portion of long-term debt and the Company's several guarantee of NOARK's obligations) and 48.4% equity, with a ratio of earnings to fixed charges of 1.9.

The percentage of debt in the Company's capital structure may in the near term increase from the current level as the Company funds expenditures which will not generate cash flow until future periods, such as the acquisition of seismic data. Over the longer term, the Company expects to lower the debt portion of its capital structure through its policy of adjusting its routine capital spending. The Company will continue to use additional debt to address extraordinary needs or opportunities, such as attractive acquisitions of gas and oil properties. Additionally, the Company may use its existing revolving credit facilities to meet seasonal or short-term requirements related to its capital expenditures.

WORKING CAPITAL

The Company maintains access to funds which may be needed to meet seasonal requirements through the revolving lines of credit explained above. The Company had net working capital of $18.5 million at the end of 1995, and $8.9 million at the end of 1994. Current assets increased by 29% to $63.9 million in 1995, while current liabilities increased 12% to $45.4 million. The increase in current assets at December 31, 1995, was due primarily to increases in income taxes receivable, inventories, and accounts receivable. The increase in accounts receivable was due to higher weather-related sales at year-end 1995. The increase in income taxes receivable relates to the carryback of a 1995 tax net operating loss which resulted from lower operating income and higher intangible drilling costs. Intangible drilling costs are deductible currently for tax purposes, but are capitalized and amortized over future periods for financial reporting purposes. The increase in inventories since December 31, 1994, is the result of injections of purchased gas into the Company' s unregulated underground storage facility. The Company has been withdrawing and selling this gas during the first quarter of 1996. The increase in current liabilities resulted primarily from an increase in accounts payable, an increase in taxes (other than income) payable, and an increase in over-recovered purchased gas costs, offset by a decrease in the current portion of long-term debt. The increase in accounts payable resulted primarily from increased amounts due for gas purchases which resulted from the higher weather-related sales in the gas distribution segment, a higher level of exploration and production capital expenditures, and from the timing of payments. Over-recovered purchased gas costs will be refunded to the Company's utility customers over future periods through the automatic cost of gas adjustment clauses in the Company's filed rate tariffs.

This discussion and analysis of financial condition and results of operations includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The Company believes that its expectations are based on reasonable assumptions. No assurances, however, can be given that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include (1) the timing and extent of changes in commodity prices for gas and oil, (2) the extent of the Company's success in discovering, developing, and producing reserves, (3) the effects of weather and regulation on the Company's gas distribution segment, and
(4) conditions in capital markets, availability of oil field services, drilling rigs, and other equipment, as well as other competitive factors during the periods covered by the forward-looking statements.

Report of Independent Auditors

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

We have audited the consolidated balance sheets of SOUTHWESTERN ENERGY COMPANY (an Arkansas corporation) AND SUBSIDIARIES as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1995. 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 in accordance with generally accepted auditing standards. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Southwestern Energy Company and Subsidiaries as of December 31, 1995 and 1994, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles.

As discussed in Notes 3 and 4 to the consolidated financial statements, effective January 1, 1993, the Company changed its methods of accounting for income taxes and for postretirement benefits other than pensions.

ARTHUR ANDERSEN LLP

Tulsa, Oklahoma
February 5, 1996

Statements of Income
Southwestern Energy Company and Subsidiaries

For the Years Ended December 31	1995	1994	1993
	($ in thousands, except per share amounts)		
OPERATING REVENUES			
Gas sales	$142,455	$160,463	$166,164
Oil sales	3,924	3,178	1,662
Gas transportation	4,964	4,721	5,177
Other	1,768	1,824	1,841
	153,111	170,186	174,844
OPERATING COSTS AND EXPENSES			
Purchased gas costs	37,133	36,395	42,962
Operating and general	44,436	42,506	40,093
Depreciation, depletion and amortization	35,992	35,546	30,944
Taxes, other than income taxes	4,362	3,657	3,281
	121,923	118,104	117,280
OPERATING INCOME	31,188	52,082	57,564
INTEREST EXPENSE			
Interest on long-term debt	12,984	9,962	10,090
Other interest charges	639	504	483
Interest capitalized	(2,456)	(1,599)	(1,548)
	11,167	8,867	9,025
OTHER INCOME (EXPENSE)	(1,227)	(2,362)	(1,657)
INCOME BEFORE INCOME TAXES, EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	18,794	40,853	46,882
INCOME TAXES			
Current	(4,908)	9,288	13,704
Deferred	12,167	6,441	6,128
	7,259	15,729	19,832
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	11,535	25,124	27,050
EXTRAORDINARY LOSS DUE TO EARLY RETIREMENT OF DEBT (NET OF $185 TAX BENEFIT)	(295)	--	--
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING FOR INCOME TAXES	--	--	10,126
NET INCOME	$ 11,240	$ 25,124	$ 37,176
EARNINGS PER SHARE			
Income before extraordinary item and cumulative effect of accounting change	$.46	$.98	$1.05
Extraordinary loss due to early retirement of debt (net of $185 tax benefit)	(.01)	--	--
Cumulative effect of change in accounting for income taxes	--	--	.39
NET INCOME	$.45	$.98	$1.44
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	25,130,781	25,684,110	25,684,110

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

Balance Sheets
Southwestern Energy Company and Subsidiaries

December 31	1995	1994
	(in thousands)	
ASSETS		
Current Assets		
Cash	$ 1,498	$ 1,152
Accounts receivable	35,541	32,325
Income taxes receivable	8,221	1,492
Inventories, at average cost	15,448	12,199
Other	3,188	2,353
Total current assets	63,896	49,521
Investments	9,114	4,877
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $51,337,000 in 1995 and $20,751,000 in 1994 excluded from amortization	517,979	435,570
Gas distribution systems	193,258	176,728
Gas in underground storage	32,616	36,629
Other	19,717	18,541
	763,570	667,468
Less: Accumulated depreciation, depletion and amortization	277,751	242,008
	485,819	425,460
Other Assets	10,264	6,216
	$569,093	$486,074
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt	$ 3,071	$ 6,071
Accounts payable	23,989	18,670
Taxes payable	2,422	2,208
Customer deposits	4,619	4,232
Over-recovered purchased gas costs, net	7,327	3,627
Other	3,982	5,827
Total current liabilities	45,410	40,635
Long-Term Debt, less current portion above	207,757	136,229
Other Liabilities		
Deferred income taxes	115,461	100,288
Deferred investment tax credits	2,103	2,416
Other	3,858	3,050
	121,422	105,754
Commitments and Contingencies		
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 27,738,084 shares	2,774	2,774
Additional paid-in capital	21,272	21,231
Retained earnings, per accompanying statements	204,632	199,430
	228,678	223,435
Less: Common stock in treasury, at cost, 3,036,735 shares in 1995 and 2,053,974 shares in 1994	33,795	19,717
Unamortized cost of restricted shares issued under stock incentive plan, 34,807 shares in 1995 and 21,499 shares in 1994	379	262
	194,504	203,456
	$569,093	$486,074

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

Statements of Cash Flows
Southwestern Energy Company and Subsidiaries

For the Years Ended December 31	1995	1994	1993
		(in thousands)	
Cash Flows From Operating Activities			
Net income	$ 11,240	$ 25,124	$ 37,176
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	36,272	35,825	31,223
Deferred income taxes	12,167	6,441	6,128
Equity in loss of partnership	696	2,818	1,788
Cumulative effect of change in accounting for income taxes	--	--	(10,126)
Change in assets and liabilities:			
(Increase) decrease in accounts receivable	(3,216)	2,569	(589)
(Increase) decrease in income taxes receivable	(6,729)	(5,354)	3,090
Increase in inventories	(3,249)	(2,619)	(1,544)
Increase in accounts payable	5,319	2,556	2,298
Increase (decrease) in taxes payable	214	(379)	21
Increase in customer deposits	387	305	417
Increase (decrease) in over-recovered purchased gas costs	3,700	(560)	(286)
Net change in other current assets and liabilities	(940)	(113)	603
Net cash provided by operating activities	55,861	66,613	70,199
Cash Flows From Investing Activities			
Capital expenditures	(101,626)	(76,854)	(59,219)
Investment in partnership	(4,968)	(2,319)	--
Decrease in gas stored underground	4,013	542	9,119
Other items	2,814	3,200	1,599
Net cash used in investing activities	(99,767)	(75,431)	(48,501)
Cash Flows From Financing Activities			
Net proceeds from issuance of Senior Notes	121,978	--	--
Net increase (decrease) in revolving long-term debt	(29,400)	21,300	(15,500)
Retirement of 10.63% Senior Notes and prepayment premium	(24,958)	--	--
Payments on other long-term debt	(3,071)	(6,000)	(835)
Purchase of treasury stock	(14,259)	--	--
Dividends paid	(6,038)	(6,164)	(5,651)
Net cash provided by (used in) financing activities	44,252	9,136	(21,986)
Increase (decrease) in cash	346	318	(288)
Cash at beginning of year	1,152	834	1,122
Cash at end of year	$ 1,498	$ 1,152	$ 834

Statements of Retained Earnings
Southwestern Energy Company and Subsidiaries

For the Years Ended December 31	1995	1994	1993
		(in thousands)	
Retained Earnings, beginning of year	$199,430	$180,470	$148,945
Net income	11,240	25,124	37,176
Cash dividends declared ($.24 per share in 1995 and 1994, and $.22 per share in 1993)	(6,038)	(6,164)	(5,651)
Retained Earnings, end of year	$204,632	$199,430	$180,470

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

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS AND CONSOLIDATION

Southwestern Energy Company is a diversified natural gas company which operates principally in the exploration and production segment and the gas distribution segment of the natural gas industry. Approximately 75% of the Company's business is derived from the exploration and production segment based on operating income. The primary areas of operations for the exploration and production segment are the Arkoma Basin of Arkansas, the Gulf Coast areas of Louisiana and Texas, the Anadarko Basin of Oklahoma, and the Delaware Basin of New Mexico. The gas distribution segment operates in northwest and northeast Arkansas and parts of Missouri, and obtains approximately 60% 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.

The consolidated financial statements include the accounts of Southwestern Energy Company and its wholly-owned subsidiaries, Southwestern Energy Production Company, SEECO, Inc., Arkansas Western Gas Company, Southwestern Energy Pipeline Company, Arkansas Western Pipeline Company, and A.W. Realty Company. 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. Certain reclassifications have been made to the prior years' financial statements to conform with the 1995 presentation.

The preparation of financial statements in conformity with generally accepted accounting principles 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.

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) 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.

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 2.2% to 6.7%. Gas in underground storage is stated at average cost.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 5 to 40 years.

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

Capitalized Interest-Interest is capitalized on the costs of unevaluated gas and oil properties excluded from amortization. In accor-dance 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 represent a diversified base of residential, commercial, and industrial users. Approximately 101,000 of these customers are served in northwest Arkansas and approximately 67,000 are served in northeast Arkansas and Missouri.

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.

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 gas sales are disproportionately allocated to owners because of marketing or other contractual arrangements. The Company's net imbalance position at December 31, 1995 and 1994 was not significant.

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.

DERIVATIVES

The Company has only limited involvement with derivative financial instruments and does not use them for trading purposes. They are used to manage defined interest rate and commodity price risks. There were no outstanding interest rate swap agreements at December 31, 1995 or 1994.

The Company uses natural gas swap agreements to hedge sales of natural gas. Under the natural gas swap agreements, the Company makes or receives payments based on the differential between a specified price and the indicated market price of natural gas. Gains and losses resulting from hedging activities are recognized when the related physical natural gas transactions are recognized. Gains or losses from natural gas swap agreements that do not qualify for accounting treatment as hedges are recognized currently as other income or expense. Gains and losses resulting from natural gas swap agreements and hedging activities have not had a material impact on the Company's results of operations.

EARNINGS PER SHARE AND SHAREHOLDERS' EQUITY

Earnings per common share are based on the weighted average number of common shares outstanding during each year.

During 1995 the Company repurchased 1,000,000 shares of its common stock for $14.3 million, and issued under a compensatory plan and for stock awards 17,239 treasury shares with a weighted average cost of $.2 million.

(2) LONG-TERM DEBT

Long-term debt as of December 31, 1995 and 1994 consisted of the following:

	1995	1994
	(in thousands)	
SENIOR NOTES		
6.70% Series due December 1, 2005	$125,000	$ --
8.69% Series due December 4, 1997	22,500	22,500
8.86% Series due in annual installments of $3.1 million through December 4, 2001	18,428	21,500
9.36% Series due in annual installments of $2.0 million beginning December 4, 2001	22,000	22,000
10.63% Series	--	24,000
	187,928	90,000
OTHER		
Variable rate (6.33% at December 31, 1995)unsecured revolving credit arrangements with two banks	22,900	52,300
Total long-term debt	210,828	142,300
Less: Current portion of long-term debt	3,071	6,071
	$207,757	$136,229

In December, 1995, the Company issued $125.0 million of 6.70% fixed rate Senior Notes. The notes mature with a single payment due after ten years. The proceeds were used to repay certain borrowings of the Company. The Company incurred $3.0 million of costs associated with the issuance of this debt. This amount has been capitalized and will be amortized over the life of the notes.

In November, 1995, the Company exercised its prepayment option on its 10.63% Senior Notes due September 30, 2001. Certain costsof the redemption were expensed in the fourth quarter of 1995 and are classified as an extraordinary loss, net of related income tax effects, in the accompanying financial statements.

The Company has several prepayment options under the terms of its other Senior Notes. Prepayments made without premium are subject to certain limitations. Other prepayment options involve the payment of premiums based in some instances on market interest rates at the time of prepayment.

At December 31, 1995, the Company had two variable rate facilities which make available $80.0 million of long-term revolving credit, of which $22.9 million was outstanding. Each facility allows the Company four interest rate options-the floating prime rate, a fixed rate tied to either short-term certificate of deposit or Eurodollar rates, or a fixed rate based on the lenders' cost of funds. The revolving credit facilities expire in 1998 and 1999. The Company intends to renew or replace the facilities prior to expiration.

The terms of the long-term debt instruments and agreements contain covenants which impose certain restrictions on the Company, including limitation of additional indebtedness and restrictions on the payment of cash dividends. At December 31, 1995, approximately $103.0 million of retained earnings was available for payment as dividends.

In 1992, the Company entered into a two-year interest rate swap agreement with a notional amount of $30.0 million to take advantage of low variable rates in relation to existing fixed rates on the Company's long-term debt. This interest rate swap agreement expired in 1994.

Aggregate maturities of long-term debt for each of the years ending December 31, 1996 through 2000, are $3.1 million, $25.6 million, $16.1 million, $13.0 million, and $3.1 million. Total interest payments of $12.9 million, $10.2 million, and $10.3 million were made in 1995, 1994, and 1993, respectively.

(3) INCOME TAXES

Effective January 1, 1993, the Company adopted SFAS No. 109, "Accounting for Income Taxes." The liability method specified by SFAS No. 109 requires the calculation of accumulated deferred income taxes by application of the tax rate expected to be in effect when the taxes will actually be paid or refunds will be received. The recognition of the cumulative effect, through December 31, 1992, of this change in accounting increased net income in the first quarter of 1993 by $10.1 million, or $.39 per share. SFAS No. 109 also required an adjustment in the third quarter of 1993 to record the effects of a legislated increase in tax rates. This adjustment decreased income before the cumulative effect of the accounting change by $1.7 million, or $.07 per share.

The provision for income taxes included the following components:

	1995	1994	1993
		(in thousands)	
Federal:			
Current	$(5,436)	$ 7,758	$11,514
Deferred	11,434	5,588	3,827
Deferred tax adjustment for tax rate increase	--	--	1,743
State:			
Current	528	1,530	2,190
Deferred	1,046	1,054	752
Investment tax credit amortization	(313)	(201)	(194)
Provision for income taxes	$ 7,259	$15,729	$19,832

The provision for income taxes was an effective rate of 38.6% in 1995, 38.5% in 1994, and 42.3% in 1993. The following reconciles the provision for income taxes included in the consolidated statements of income with the provision which would result from application of the statutory federal tax rate to pretax financial income:

	1995	1994	1993
		(in thousands)	
Expected provision at federal statutory rate of 35%	$6,578	$14,299	$16,409
Increase (decrease) resulting from:			
State income taxes, net of federal income tax benefit	1,023	1,682	1,914
Percentage depletion on gas and oil production	(70)	(96)	(117)
Adjustment to deferred taxes for tax rate increase	--	--	1,743
Investment tax credit amortization	(313)	(201)	(194)
Other	41	45	77
Provision for income taxes	$7,259	$15,729	$19,832

The components of the Company's net deferred tax liability as of December 31, 1995 and 1994 were as follows:

	1995	1994
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$103,612	$ 89,289
Stored gas differences	5,435	5,736
Deferred purchased gas costs	236	1,557
Prepaid pension costs	1,561	1,628
Book over tax basis in partnerships	4,712	3,535
Other	971	1,095
	116,527	102,840
Deferred tax assets:		
Accrued compensation	681	700
Other	644	370
	1,325	1,070
Net deferred tax liability	$115,202	$101,770

Total income tax payments of $.9 million, $14.6 million, and $10.2 million were made in 1995, 1994, and 1993, respectively.

(4) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

Substantially all employees are covered by the Company's defined benefit pension plan. Benefits are based on years of benefit service and the employee's "average compensation," as defined. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plan with sufficient assets to meet future benefit payment requirements and which are tax deductible.

Plan assumptions for 1995 and 1994 included an expected long-term rate of return on plan assets of 9%, a weighted average discount rate of 8.5% in 1995 and 7.5% in 1994 for the net pension cost computation, and a salary progression rate of 5%. The reconciliation of prepaid pension cost at December 31, 1995 utilizes a discount rate of 7.5% for future settlements.

The following table sets forth the plan's funded status and amounts recognized in the Company's balance sheets at December 31, 1995 and 1994:

	1995	1994
	(in thousands)	
Actuarial present value of benefit obligations:		
Vested benefits	$(25,789)	$(20,643)
Nonvested benefits	(1,860)	(1,635)
Accumulated benefit obligation	(27,649)	(22,278)
Effect of projected future compensation levels	(8,623)	(6,368)
Projected benefit obligation	(36,272)	(28,646)
Plan assets at fair value, primarily common stocks and bonds	49,570	36,675
Plan assets in excess of projected benefit obligation	13,298	8,029
Unrecognized net gain	(8,956)	(3,617)
Unrecognized net asset	(952)	(1,135)
Unrecognized prior service cost	397	454
Prepaid pension cost	$ 3,787	$ 3,731

Net pension cost for 1995, 1994, and 1993 included the following components:

	1995	1994	1993
		(in thousands)	
Service costs (benefits earned during the period)	$ 1,101	$ 1,217	$ 897
Interest cost on projected benefit obligation	2,316	2,280	1,999
Actual return on plan assets	(15,172)	(791)	(2,819)
Net amortization and deferral	11,699	(2,643)	(673)
Net pension cost (credit)	$ (56)	$ 63	$ (596)

The Company also has a supplemental retirement plan which provides for certain pension benefits. Net pension cost recorded for this plan was $221,000, $201,000, and $628,000 in 1995, 1994, and 1993, respectively. In 1993, this plan was funded with $1.2 million. At December 31, 1995, the supplemental retirement plan had an accrued pension cost of $91,000.

Effective January 1, 1993, the Company adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." Under SFAS No. 106, the cost of those benefits is accrued over the period the employee provides services to the Company. Prior to 1993, postretirement benefit expenses were recognized on a pay-as-you-go basis and were not material. The Company currently funds postretirement benefits as claims are incurred.

The Company provides postretirement health care and life insurance benefits to eligible employees. 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.

A significant portion of the postretirement benefit cost relates to the Company's utility operations and has been deferred as a regulatory asset. Net postretirement benefit cost for 1995 and 1994 included the following components:

	1995	1994
	(in thousands)	
Service cost of benefits earned during the year	$110	$ 79
Amortization of transition amount	103	178
Amortization of unrecognized gain	32	17
Interest cost on accumulated postretirement benefit obligation (APBO)	218	164
Net postretirement benefit cost	$463	$438

The APBO as of December 31, 1995 and 1994 was comprised of the following:

	1995	1994
	(in thousands)	
Retirees	$1,109	$ 766
Active participants, fully eligible	303	442
Other participants	805	804
Total APBO	$2,217	$2,012

In determining the APBO, assumed weighted average discount rates of 7.5% and 8.5% were used for 1995 and 1994, respectively. An increase of 10% in the cost of covered health care benefits was assumed for 1996. This rate is assumed to decrease ratably to 6.0% over 8 years and remain at that level thereafter. The effect of a one percentage point increase in the assumed health care cost trend rate for each future year would increase the total APBO at year-end 1995 by $253,000 and the 1995 net postretirement benefit cost by $29,000.

(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:

	1995	1994	1993
		(in thousands)	
Sales	$ 63,205	$ 80,123	$ 79,374
Production (lifting) costs	(7,930)	(6,771)	(6,341)
Depreciation, depletion and amortization	(29,607)	(29,738)	(25,686)
	25,668	43,614	47,347
Income tax expense	(9,831)	(16,684)	(18,081)
Results of operations	$ 15,837	$ 26,930	$ 29,266

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

The table below sets forth capitalized costs incurred in gas and oil property acquisition, exploration and development activities during 1995, 1994, and 1993:

	1995	1994	1993
		(in thousands)	
Property acquisition costs	$27,715	$21,972	$ 5,920
Exploration costs	29,843	12,419	11,695
Development costs	24,429	20,943	19,722
Capitalized costs incurred	$81,987	$55,334	$37,337
Amortization per Mcf equivalent	$.817	$.759	$.710

The following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December 31, 1995 and 1994:

	1995	1994
	(in thousands)	
Proved properties	$463,868	$405,081
Unproved properties	54,111	30,489
Total capitalized costs	517,979	435,570
Less: Accumulated depreciation, depletion and amortization	206,148	176,764
Net capitalized costs	$311,831	$258,806

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 1995. Included in these costs is $6.6 million representing leasehold and seismic costs related to the remaining unevaluated portion of acreage located on the Fort Chaffee military reservation. These costs are expected to be evaluated and subjected to amortization within the next several years as this acreage is further explored and developed. Included in exploration costs is $4.7 million of seismic costs related to the Company's 50% interest in a joint venture seismic program in the Atchafalaya Basin in Louisiana. These costs and subsequent costs to be incurred 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.

	1995	1994	1993	Prior	Total
			(in thousands)		
Property acquisition costs	$14,207	$3,667	$1,084	$6,595	$25,553
Exploration costs	17,322	3,202	1,204	347	22,075
Capitalized interest	2,379	535	255	540	3,709
	$33,908	$7,404	$2,543	$7,482	$51,337

(6) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 1995, 1994, and 1993:

	1995		1994		1993	
	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	316,098	1,231	318,776	479	312,291	359
Revisions of previous estimates	(25,970)	(199)	(16,551)	(258)	(4,110)	(25)
Extensions, discoveries, and other additions	34,801	498	30,932	189	46,069	250
Production	(34,515)	(229)	(37,706)	(200)	(35,693)	(97)
Acquisition of reserves in place	4,462	851	20,647	1,038	222	--
Disposition of reserves in place	--	--	--	(17)	(3)	(8)
Proved reserves, end of year	294,876	2,152	316,098	1,231	318,776	479
Proved, developed reserves:						
Beginning of year	261,690	1,116	260,240	469	246,904	337
End of year	248,714	1,975	261,690	1,116	260,240	469

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas 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. Substantially all quantities of gas and oil reserves owned by the Company were estimated by the independent petroleum engineering firm of K & A Energy Consultants, Inc.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 1995, 1994, and 1993:

	1995	1994	1993
		(in thousands)	
Future cash inflows	$ 751,261	$ 683,438	$ 745,967
Future production and development costs	(106,092)	(96,813)	(85,609)
Future income tax expense	(229,064)	(207,359)	(236,170)
Future net cash flows	416,105	379,266	424,188
10% annual discount for estimated timing of cash flows	(212,583)	(189,774)	(196,913)
Standardized measure of discounted future net cash flows	$ 203,522	$ 189,492	$ 227,275

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 pretax cash inflows. Future income taxes were computed by applying the year-end statutory rate, after consideration of permanent differences and enacted tax legislation, to the excess of pretax cash inflows over the Company's tax basis in the associated proved gas and oil properties. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the standardized measure.

Following is an analysis of changes in the standardized measure during 1995, 1994, and 1993:

	1995	1994	1993
		(in thousands)	
Standardized measure, beginning of year	$189,492	$227,275	$209,970
Sales and transfers of gas and oil produced, net of production costs	(55,275)	(73,352)	(73,017)
Net changes in prices and production costs	39,928	(29,344)	22,392
Extensions, discoveries, and other additions, net of future production and development costs	49,471	43,458	74,511
Revisions of previous quantity estimates	(29,851)	(19,225)	(5,217)
Accretion of discount	28,733	34,968	31,885
Net change in income taxes	(9,073)	24,564	(13,524)
Changes in production rates (timing)and other	(9,903)	(18,852)	(19,725)
Standardized measure, end of year	$203,522	$189,492	$227,275

(7) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

The Company holds a general partnership interest in NOARK of 47.93% and is the pipeline's operator. NOARK is a 258 mile long intrastate gas transmission system which extends across northern Arkansas and was placed in service in September, 1992. The Company's investment in NOARK totaled $9.0 million at December 31, 1995 and $4.8 million at December 31, 1994. The Company's investment in NOARK includes advances of $5.0 million made during 1995 and $2.3 million during 1994, primarily to provide certain minimum cash balances to service NOARK's long-term debt. See Note 12 for further discussion of NOARK's funding requirements and the Company's investment in NOARK.

NOARK's financial position at December 31, 1995 and 1994 is summarized below:

	1995	1994
	(in thousands)	
Current assets	$ 870	$ 1,078
Noncurrent assets	98,048	100,662
	$98,918	$101,740
Current liabilities	$ 6,624	$ 6,009
Long-term debt	76,700	86,250
Loans from general partners	11,505	3,225
Partners' capital	4,089	6,256
	$98,918	$101,740

The Company's share of NOARK's pretax loss, before the effect of accrued interest expense on general partner loans, was $.7 million, $2.8 million, and $1.8 million for 1995, 1994, and 1993, respectively. The Company records its share of NOARK's pretax loss in other income (expense) on the statements of income. The 1995 pretax loss included $2.9 million of income for the Company's share of a $6.0 million settlement of contract issues with one of NOARK's transporters.

NOARK's results of operations for 1995, 1994, and 1993 are summarized below:

	1995	1994	1993
		(in thousands)	
Operating revenues	$11,657	$10,111	$ 8,301
Pretax loss	$(2,167)	$(5,917)	$(3,778)

(8) DISCLOSURES ABOUT THE 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 and Customer Deposits - The carrying amount is a reasonable estimate of fair value.

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

The estimated fair values of the Company's financial instruments as of December 31, 1995 and 1994 were as follows:

	1995		1994	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash	$1,498	$1,498	$1,152	$1,152
Customer deposits	$4,619	$4,619	$4,232	$4,232
Long-term debt	$210,828	$216,364	$142,300	$144,245

Anticipated regulatory treatment of the excess of fair value over carrying value of the portion of the Company's long-term debt attributable to its regulatory activities, if in fact such debt were settled at amounts approximating those above, would dictate that these amounts be used to increase the Company's rates over a prescribed amortization period. Accordingly, any settlement would not result in a material impact on the Company's financial position or results of operations.

(9) SEGMENT INFORMATION

Intersegment sales by the exploration and production segment to the gas distribution segment are priced in accordance with terms of existing gas contracts and current market conditions. Following is industry segment data for the years ended December 31, 1995, 1994, and 1993:

	1995	1994	1993
		(in thousands)	
REVENUES			
Exploration and production	$ 63,523	$ 80,123	$ 79,374
Gas distribution	119,855	127,060	131,892
Other	336	308	262
Eliminations	(30,603)	(37,305)	(36,684)
	$153,111	$170,186	$174,844
INTERSEGMENT REVENUES			
Exploration and production	$ 29,811	$ 36,465	$ 36,091
Gas distribution	536	584	337
Other	256	256	256
	$ 30,603	$ 37,305	$ 36,684
OPERATING INCOME			
Exploration and production	$ 20,523	$ 38,888	$ 42,608
Gas distribution	11,133	13,386	15,261
Corporate expenses	(468)	(192)	(305)
	$ 31,188	$ 52,082	$ 57,564
IDENTIFIABLE ASSETS			
Exploration and production	$346,514	$288,175	$236,968
Gas distribution	183,410	171,471	186,704
Other	39,169	26,428	21,782
	$569,093	$486,074	$445,454
DEPRECIATION, DEPLETION AND AMORTIZATION			
Exploration and production	$ 29,607	$ 29,738	$ 25,686
Gas distribution	5,338	4,981	4,564
Other	1,047	827	694
	$ 35,992	$ 35,546	$ 30,944
CAPITAL ADDITIONS			
Exploration and production	$ 82,237	$ 55,449	$ 37,411
Gas distribution	18,523	17,577	19,892
Other	866	3,828	1,916
	$101,626	$ 76,854	$ 59,219

(10) STOCK OPTIONS

The Southwestern Energy Company 1993 Stock Incentive Plan (1993 Plan) provides for the compensation of officers and key employees of the Company and its subsidiaries. The 1993 Plan provides for grants of options, shares of restricted stock, and stock bonuses that in the aggregate do not exceed 1,275,000 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 do not exceed 1,275,000 shares, and the grant of limited and tandem SARs (all terms as defined in the 1993 Plan). 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 plan.

At December 31, 1995, there were options for 1,024,108 shares outstanding under the 1993 Plan at option prices ranging from $13 3/8 to $17 1/8, representing the fair market value at the dates of grant. Of the total, 780,000 performance accelerated options were granted in 1994 at an option price of $14 5/8. These options vest over a four-year period beginning six years from the date of grant or earlier if certain corporate performance criteria are achieved. The remaining options, granted in 1993, 1994, and 1995, vest to employees over a three-year period from the date of grant. Options for 28,774 shares were exercisable at December 31, 1995. All options expire ten years from the date of grant. Additionally, 38,965 shares of restricted stock have been granted to employees during the period 1993 through 1995. Of this total, 6,855 shares issued in 1995 vest over a three-year period and the remaining shares vest over a five-year period. The related compensation expense is being amortized over the vesting periods.

Under the Company's 1985 Nonqualified Stock Option Plan, there were options for 427,050 shares and 84,900 SARs outstanding at December 31, 1995 at prices ranging from $5.58 to $12.81. All options are currently exercisable. All options expire ten years from the date of grant.

The Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors provides for annual stock option grants of 12,000 shares (with 12,000 limited SARs) to each non-employee director. Options may be awarded under the plan on no more than 240,000 shares. Options are issued at fair market value on the date of grant and become exercisable in installments at a rate of 25% per year for each twelve months' service as a director. At December 31, 1995, there were options for 99,000 shares outstanding at option prices ranging from $12 7/8 to $17 1/2. Options for 21,000 shares are currently exercisable.

(11) COMMON STOCK PURCHASE RIGHTS

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 $25.00, subject to adjustment. These rights will become exercisable in the event that a person or group acquires or commences a tender offer for 20% 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 20% of the common stock (10% or more if the Board determines such acquiror is adverse), rightholders (other than the 20% 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 combi-nation, 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 $.003 per right 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 (nonmanagement directors who are not affiliated with the proposed acquiror). These rights expire in 1999.

(12) CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK are required to severally guarantee the availability of certain minimum cash balances to service the 9.7375% Senior Secured Notes used to finance a portion of NOARK's total construction cost. At December 31, 1995, the Senior Secured Notes had a remaining balance of $56.7 million and a remaining term of 14 years. At December 31, 1995, NOARK also had an unsecured long-term revolving credit agreement in the amount of $30.0 million with a group of banks, of which $23.2 million was outstanding. Amounts borrowed under the long-term revolving credit facility are severally guaranteed by the Company and an affiliate of the other general partner. The Company's share of the several guarantee of the notes and the line of credit is 60%. Additionally, the Company's gas distribution subsidiary has a transportation contract with an original term of ten years with NOARK for firm capacity of 41 MMcfd. The remaining term of that contract is seven years and is renewable year-to-year until terminated by 180 days' notice.

In late 1993, a transporter of gas on NOARK's pipeline system filed suit against NOARK, the Company, and certain of its affiliates, and, effective January 1, 1994, ceased transporting gas under its firm transportation agreement with NOARK. In December, 1995, the parties to the lawsuit settled prior to going to trial. In exchange for a $6.0 million payment to NOARK, the transporter was released from its obligations under its firm transportation agreement. The Company will be required to fund its share of any cash flow deficiencies to the extent they are not funded by the available line of credit. Management of the Company and the NOARK partners continue to investigate options available to NOARK. However, management believes that no write-down of its investment in NOARK is appropriate at this time and 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.

The Company has been advised of a potential claim against it involving the disputed ownership of overriding royalty interests in a number of oil and gas properties and related matters. The Company has begun discussions with the claimant and has engaged special counsel to assist it in a preliminary investigation of the claim's merits. The Company is unable to predict at this time whether litigation will be commenced in respect of this claim or how the claim will ultimately be resolved. While the amount of the potential claim is significant in the aggregate, management believes, based on its preliminary investigation, that the Company's ultimate liability, if any, will not be material to its consolidated financial position or results of operations.

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 noncapital 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 condition or reported results of operations of the Company.

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

(13) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 1995 and 1994:

Quarter Ended	March 31	June 30	September 30	December 31
	(in thousands, except per share amounts)			
1995				
Operating revenues	$51,751	$30,642	$25,454	$45,264
Operating income	$15,090	$ 3,927	$ 1,955	$10,216
Income (loss) before extraordinary item	$ 7,102	$ 445	$(1,081)	$ 5,069
Net income (loss)	$ 7,102	$ 445	$(1,081)	$ 4,774
Earnings (loss) per share before extraordinary item	$.28	$.02	$(.04)	$.20
Earnings (loss) per share	$.28	$.02	$(.04)	$.19
1994				
Operating revenues	$65,430	$34,605	$27,808	$42,343
Operating income	$23,525	$10,471	$ 6,327	$11,759
Net income	$12,994	$ 4,834	$ 2,128	$ 5,168
Earnings per share	$.51	$.18	$.09	$.20

Financial and Operating Statistics

	1995	1994	1993	1992	1991	1990
FINANCIAL REVIEW (in thousands)						
Operating revenues:						
Exploration and production	$ 63,523	$ 80,123	$ 79,374	$ 60,554	$ 49,392	$ 41,489
Gas distribution	119,855	127,060	131,892	117,495	121,302	108,911
Other	336	308	262	256	256	256
Intersegment revenues	(30,603)	(37,305)	(36,684)	(34,475)	(34,511)	(33,586)
	153,111	170,186	174,844	143,830	136,439	117,070
Operating costs and expenses:						
Purchased gas costs	37,133	36,395	42,962	35,848	40,423	37,678
Operating and general	44,436	42,506	40,093	34,970	32,609	28,134
Depreciation, depletion and amortization	35,992	35,546	30,944	23,880	18,248	14,756
Taxes, other than income taxes	4,362	3,657	3,281	3,144	3,017	2,885
	121,923	118,104	117,280	97,842	94,297	83,453
Operating income	31,188	52,082	57,564	45,988	42,142	33,617
Interest expense, net	(11,167)	(8,867)	(9,025)	(9,983)	(9,813)	(10,530)
Other income (expense)	(1,227)	(2,362)	(1,657)	(421)	(107)	(17)
Income before income taxes, extraordinary items and the cumulative effect of accounting change	18,794	40,853	46,882	35,584	32,222	23,070
Income taxes:						
Current	(4,908)	9,288	13,704	7,403	7,158	4,994
Deferred	12,167	6,441	6,128	5,916	4,999	3,568
	7,259	15,729	19,832	13,319	12,157	8,562
Income before extraordinary item and cumulative effect of accounting change	11,535	25,124	27,050	22,265	20,065	14,508
Extraordinary loss due to early retirement of debt (net of $185 tax benefit)	(295)	--	--	--	--	--
Extraordinary loss due to redemption of convertible debentures (net of $257 tax benefit)	--	--	--	--	--	(433)
Cumulative effect of change in accounting for income taxes	--	--	10,126	--	--	--
Net income	$ 11,240	$ 25,124	$ 37,176	$ 22,265	$ 20,065	$ 14,075
Cash flow from operations (in thousands)	$ 55,861	$ 66,613	$ 70,199	$ 49,730	$ 34,986	$ 36,495
Return on equity	5.78%	12.35%	14.66%/(1)/	14.53%	14.75%	11.66%
Gross profit margin	20.37%	30.60%	32.92%	31.97%	30.89%	28.72%
Net profit margin	7.34%	14.76%	15.47%/(1)/	15.48%	14.71%	12.02%
COMMON STOCK STATISTICS/(2)/						
Earnings per share before extraordinary item and cumulative effect of accounting change	$.46	$.98	$1.05	$.87	$.78	$.57
Earnings per share	$.45	$.98	$1.44	$.87	$.78	$.56
Cash dividends declared and paid per share	$.24	$.24	$.22	$.20	$.19	$.19
Book value per share	$7.87	$7.92	$7.18	$5.97	$5.30	$4.70
Market price at year-end	$12.75	$14.88	$18.00	$12.96	$10.50	$10.42
Number of shareholders of record at year-end	2,759	2,875	3,005	2,930	2,989	3,136
Average shares outstanding	25,130,781	25,684,110	25,684,110	25,683,963	25,678,011	25,270,674
CAPITALIZATION (in thousands)						
Long-term debt, including current portion	$210,828	$142,300	$127,000	$143,335	$134,104	$125,535
Common shareholders' equity	194,504	203,456	184,530	153,233	136,041	120,709
Total capitalization	$405,332	$345,756	$311,530	$296,568	$270,145	$246,244
Total assets	$569,093	$486,074	$445,454	$427,175	$392,208	$366,313
Capitalization ratios:						
Debt (excluding current portion)	51.65%	40.10%	40.19%	48.31%	49.08%	50.39%
Equity	48.35%	59.90%	59.81%	51.69%	50.92%	49.61%
CAPITAL EXPENDITURES (in millions)						
Exploration and production	$82.2	$55.4	$37.4	$30.8	$30.3	$23.4
Gas distribution	18.5	17.6	19.9	12.2	7.9	9.3
Other	.9	3.9	1.9	1.9	.7	.7
	$101.6	$76.9	$59.2	$44.9	$38.9	$33.4

/(1)/Before the cumulative effect of accounting change.

/(2)/All share and per share data have been restated to reflect the effect of a three-for-one stock split distributed in 1993.

	1995	1994	1993	1992	1991	1990
Natural Gas and Oil Wells Completed						
Producers:						
Gross	70.0	78.0	57.0	69.0	25.0	25.0
Net	43.8	50.2	40.7	54.6	11.8	9.1
Dry holes:						
Gross	39.0	30.0	28.0	29.0	12.0	10.0
Net	26.5	16.5	14.5	19.5	4.1	2.1
Total:						
Gross	109.0	108.0	85.0	98.0	37.0	35.0
Net	70.3	66.7	55.2	74.1	15.9	11.2

At the end of 1995, the Company was a participant in 17.0 (12.4 net) wells in process.

	1995	1994	1993	1992	1991	1990
Natural Gas and Oil Produced						
Natural gas:						
Production, Bcf	34.5	37.7	35.7	25.8	20.3	16.7
Average price per Mcf	$1.72	$2.04	$2.18	$2.26	$2.25	$2.33
Oil:						
Production, MBbls	229	200	97	120	176	112
Average price per barrel	$17.15	$15.89	$17.20	$19.75	$20.67	$22.89
Average production (lifting) cost per Mcf equivalent	$.22	$.17	$.18	$.16	$.19	$.16
Proved reserves at year-end:						
Natural gas, Bcf	294.9	316.1	318.8	312.3	307.5	304.5
Oil, MBbls	2,152	1,231	479	359	505	773
Utility Operating Data						
Sales volumes, Bcf:						
Residential	12.1	11.6	12.9	10.8	10.9	10.1
Commercial	7.6	7.2	7.8	6.6	6.7	6.3
Industrial	7.7	7.5	6.1	6.1	9.5	10.2
Transportation volumes, Bcf:						
End-use	5.2	4.8	5.6	5.2	1.3	.1
Off-system	9.8	10.7	11.7	2.5	.2	.3
	42.4	41.8	44.1	31.2	28.6	27.0
Average sales customers:						
Residential	144,828	140,684	137,087	133,103	129,379	127,142
Commercial	19,502	18,872	18,511	18,141	17,880	17,680
Industrial	342	341	346	348	370	366
	164,672	159,897	155,944	151,592	147,629	145,188
Sales and transportation revenues (in thousands):						
Residential	$ 59,523	$ 62,565	$ 67,502	$ 59,747	$ 58,372	$ 48,407
Commercial	31,018	32,252	35,311	31,425	30,718	27,535
Industrial	22,466	25,191	21,757	20,502	29,187	30,463
Transportation	4,964	4,721	5,177	3,597	857	179
	$117,971	$124,729	$129,747	$115,271	$119,134	$106,584
Miles of pipe:						
Gathering	434	405	398	383	375	371
Transmission	1,348	1,346	1,335	1,328	1,326	1,326
Distribution	4,451	4,246	4,160	4,090	4,002	3,931
	6,233	5,997	5,893	5,801	5,703	5,628
Degree days	4,376	4,161	4,929	4,104	4,095	3,972
Percent of normal	99%	95%	113%	92%	93%	90%

Shareholder Information

ANNUAL MEETING

The Annual Meeting of Shareholders of Southwestern Energy Company will be held at the Northwest Arkansas Holiday Inn in Springdale, Arkansas, on Monday, May 13, 1996, at 11:00 a.m. Central Daylight Time.

STOCK EXCHANGE LISTING

Southwestern Energy Company's common stock is traded on the New York Stock Exchange under the symbol SWN and is listed in alphabetical quotation listings in most major newspapers as SowestEngy.

INDEPENDENT AUDITORS

Arthur Andersen LLP
6450 South Lewis
Suite 300
Tulsa, Oklahoma 74136-1068

FINANCIAL INFORMATION

Financial analysts and investors who need additional information should contact Stanley D. Green, Executive Vice President-Finance and Corporate Development, at corporate headquarters, 501-521-1141.

TRANSFER AGENT AND REGISTRAR

First Chicago Trust Company of New York
525 Washington Blvd.
Jersey City, NJ 07310
Phone 1-800-446-2617

DIVIDEND REINVESTMENT PLAN

Southwestern Energy Company offers holders of record of its common stock the opportunity to purchase additional shares through its Dividend Reinvestment Plan. Dividends and/or optional cash investments of up to $1,000 monthly may be used to purchase additional shares of the Company's stock for nominal service and broker's fees. Information about the Plan is available from the administrator:

First Chicago Trust Company of New York
P.O. Box 2598
Jersey City, NJ 07303-2598
Phone 1-800-446-2617

ANNUAL REPORT

This annual report and the statements contained herein are submitted for the general information of shareholders of the Company and are not intended to induce any sale or purchase of securities or to be used in connection therewith.

The 1995 Annual Report filed with the Securities and Exchange Commission on Form 10-K is available to shareholders upon request by writing to the Secretary at corporate headquarters.

MARKET PRICES AND QUARTERLY DIVIDENDS PAID

	Range of Market Prices				Cash Dividends Paid	
	1995		1994		1995	1994
	High	Low	High	Low		
March 31	$15.13	$11.75	$18.88	$15.13	$.06	$.06
June 30	$15.50	$13.63	$17.75	$15.50	$.06	$.06
September 30	$14.25	$12.00	$17.88	$15.50	$.06	$.06
December 31	$14.25	$12.25	$17.75	$14.00	$.06	$.06

Market prices represent transactions on the New York Stock Exchange.

Southwestern Energy Company and Subsidiaries
APPENDIX to 1995 ANNUAL REPORT TO SHAREHOLDERS

Description of Exploration & Production Operating Areas:

Southwestern conducts its exploration and production efforts primarily in four areas; the Arkoma Basin, the Anadarko Basin, the Gulf Coast, and the Delaware Basin of New Mexico. The Arkoma Basin is located in the central section of western Arkansas and the central section of eastern Oklahoma. Southwestern's activities are concentrated in the historically productive Arkansas section of the Arkoma Basin. The Anadarko Basin covers most of the western part of Oklahoma and extends to the northwest into the northern panhandle of Texas and the panhandle area of Oklahoma. Southwestern's Gulf Coast operations include both onshore and offshore activity along both the Texas and Louisiana coasts. The Delaware Basin is located in the southeast corner of New Mexico and extends to the south into western Texas.

Description of Gas Distribution Operating Areas:

Arkansas Western Gas Company's (AWG) northwest Arkansas gas utility system gathers its gas supply from the Arkoma Basin where it also provides distribution service to communities in that area, including the towns of Ozark and Clarksville. AWG's transmission and distribution lines extend north and supply communities in the northwest part of the state, including the towns of Fayetteville, Springdale, and Rogers. AWG's service area also extends east to the Harrison and Mountain Home areas. This eastern section of the AWG system receives a portion of its gas supply from a lateral line off of the NOARK Pipeline System (NOARK) as discussed below. Through its division, Associated Natural Gas Company (Associated), AWG provides distribution of natural gas to communities in northeast Arkansas and parts of Missouri. Major communities served in northeast Arkansas include Blytheville, Piggott, and Osceola. The Associated distribution system also serves the "bootheel" area in southeast Missouri, including the communities of Sikeston, New Madrid, and Caruthersville and extends north to the Jackson area. In addition, Associated provides service to Butler, Missouri, near the state's western border and Kirksville, Missouri, near the state's northern border through connections off of interstate pipelines in those areas.

Description of NOARK Pipeline System Operating Area:

Southwestern Energy Pipeline Company owns a 47.93% general partnership interest in NOARK, a 258-mile intrastate pipeline that ties the Claimant's gathering and transmission pipeline systems in northwest Arkansas to its distribution systems in northeast Arkansas and southeast Missouri. NOARK starts near Forth Smith, at the Fort Chaffee military reservation, and extends east through the Arkoma Basin and across northern Arkansas. A lateral from NOARK extends north and connects to AWG's distribution line in the Mountain Home area. NOARK crosses three interstate pipelines in northeast Arkansas and ends at an interconnection with Arkansas Western Pipeline Company's 8-mile interstate pipeline at the Arkansas/Missouri border. This pipeline transports gas from NOARK to Associated's distribution system.

Operating Properties:

ACREAGE AND PRODUCING WELLS

	Undeveloped		Developed		Wells	
	Gross	Net	Gross	Net	Gross	Net
Arkansas	175,335	84,566	298,523	138,425	761	395.3
Louisiana	37,485	21,880	12,890	4,060	34	19.6
Oklahoma	21,799	15,601	51,551	27,494	471	245.5
Texas	31,517	15,416	48,687	11,887	39	8.2
New Mexico	17,200	8,967	1,000	161	5	1.6
Other areas	10,154	8,564	4,018	964	11	3.0
	293,490	154,994	416,669	182,991	1,321	673.2

GAS DISTRIBUTION SYSTEMS MILES OF PIPE

	AWG	Associated	Total
Gathering	434	--	434
Transmission	745	603	1,348
Distribution	2,867	1,584	4,451
	4,046	2,187	6,233

ARTICLE 5
MULTIPLIER: 1,000

PERIOD TYPE	YEAR
FISCAL YEAR END	DEC 31 1995
PERIOD END	DEC 31 1995
CASH	1,498
SECURITIES	0
RECEIVABLES	35,541
ALLOWANCES	0
INVENTORY	15,448
CURRENT ASSETS	63,896
PP&E	763,570
DEPRECIATION	277,751
TOTAL ASSETS	569,093
CURRENT LIABILITIES	45,410
BONDS	207,757
PREFERRED MANDATORY	0
PREFERRED	0
COMMON	2,774
OTHER SE	191,730
TOTAL LIABILITY AND EQUITY	569,093
SALES	146,379
TOTAL REVENUES	153,111
CGS	0
TOTAL COSTS	121,923
OTHER EXPENSES	0
LOSS PROVISION	0
INTEREST EXPENSE	11,167
INCOME PRETAX	18,794
INCOME TAX	7,259
INCOME CONTINUING	11,535
DISCONTINUED	0
EXTRAORDINARY	(295)
CHANGES	0
NET INCOME	11,240
EPS PRIMARY	.45
EPS DILUTED	0

End of Filing