UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2000

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________ to __________________

Commission File Number 333-52664

BLACK HILLS CORPORATION

Incorporated in South Dakota   IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

Registrant's telephone number, including area code
(605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

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.
X

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At February 28, 2001 $843,247,880

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 28, 2001
Common stock, $1.00 par value	22,951,394 shares

Documents Incorporated by Reference

1. Definitive Proxy Statement of the Registrant filed pursuant to Regulation 14A for the 2001 Annual Meeting of Stockholders to be held on May 30, 2001, is incorporated by reference in Part III.

FORWARD-LOOKING STATEMENTS

This Form 10-K includes "forward-looking statements" as defined by the Securities and Exchange Commission. These statements concern our plans, expectations and objectives for future operations. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. The words "believe," "plan," "intend," "anticipate," "estimate," "project" and similar expressions are also intended to identify forward-looking statements. These forward-looking statements include, among others, such things as:

- expansion and growth of our business and operations;
- future financial performance;
- future acquisition and development of power plants;
- future production of coal, oil and natural gas;
- reserve estimates; and
- business strategy.

These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from those contained in the forward-looking statements, including the following factors:

- prevailing governmental polices and regulatory actions with respect to allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power and other capital investments, and present or prospective wholesale and retail competition;
- changes in and compliance with environmental and safety laws and policies;
- weather conditions;
- population growth and demographic patterns;
- competition for retail and wholesale customers;
- pricing and transportation of commodities;
- market demand, including structural market changes;
- changes in tax rates or policies or in rates of inflation;
- changes in project costs;
- unanticipated changes in operating expenses or capital expenditures;
- capital market conditions;
- technological advances;
- competition for new energy development opportunities; and
- legal and administrative proceedings that influence our business and profitability.

TABLE OF CONTENTS

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

We are a growth oriented, diversified energy holding company operating principally in the United States. Our regulated and unregulated businesses have expanded significantly in recent years. Our independent energy group produces and markets power and fuel. We produce and sell electricity in a number of markets, with a strong emphasis on the western United States. We produce coal, natural gas and crude oil primarily in the Rocky Mountain region and market fuel products nationwide. We also own Black Hills Power, Inc., an electric utility serving 58,600 customers in South Dakota, Wyoming and Montana. Our communications group offers state-of-the-art broadband communication services to residential and business customers in Rapid City and the northern Black Hills region of South Dakota. Our predecessor company was incorporated and began providing electric utility service in 1941 and began selling and marketing various forms of energy on an unregulated basis in 1956.

As the following table illustrates, we have experienced significant growth over the last five years, primarily as a result of the expansion of our independent energy business and increases in wholesale electric sales.

	2000	1999	1998	1997	1996
Net income (in thousands):					
Electric	$ 37,105	$ 27,286	$ 24,825	$ 22,106	$ 18,333
Independent energy	28,946	11,882	10,014	10,408	11,933
Communications and other	(13,203)	(2,101)	(226)	(155)	(14)
Oil and gas write-down	--	--	(8,805)	--	--
	$ 52,848	$ 37,067	$ 25,808	$ 32,359	$ 30,252
Earnings per share	$2.37	$1.73	$1.60(2)	$1.49	$1.40
Assets (in thousands)	$1,320,320	$668,492	$559,417	$508,741	$467,354
Capital expenditures (in thousands)	$177,189(1)	$154,609	$27,225	$28,319	$24,388
Electric sales (megawatthours):					
Regulated utility					
Firm electric sales	1,973,066	1,920,005	1,923,331	1,932,347	1,710,571
Wholesale off-system	684,378	445,712	371,104	279,612	249,100
Total utility	2,657,444	2,365,717	2,294,435	2,211,959	1,959,671
Non-regulated sales	236,279	-	-	-	-
Total electric sales	2,893,723	2,365,717	2,294,435	2,211,959	1,959,671
Average daily marketing volumes:					
Natural gas (MMbtus)	860,800	635,500	524,800	231,000	28,200(3)
Crude oil (barrels)	44,300	19,270	19,000	12,600(3)	-
Coal (tons)	4,400	4,500	4,400(3)	-	-
Generating capacity (megawatts)					
Utility (owned generation)	393	353	353	353	353
Utility (purchased capacity)	70	75	75	75	75
Independent power	250	--		--	--
Total generating capacity	713	428	428	428	428
Oil and gas reserves (MMcfe)	44,882	44,114	30,160	24,022	17,330

(1) Excludes the non-cash acquisition of Indeck Capital, Inc.

(2) Excludes impact of $0.41 per share non-cash write-down of oil and gas properties due to historically low oil prices, lower natural gas prices and a decline in the value of unevaluated properties.

(3) Since date of inception of marketing operations.

For additional information on our business segments see - "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS and Note 13 of NOTES TO CONSOLIDATED FINANCIAL STATEMENTS."

Holding Company Formation

At our annual meeting of shareholders on June 20, 2000, our shareholders approved the formation of a holding company structure through a "plan of exchange" between Black Hills Corporation and Black Hills Holding Corporation. The plan of exchange provided that each share of Black Hills Corporation common stock would be exchanged for one share of common stock of the holding company.

On December 22, 2000, articles of exchange were filed with the South Dakota Secretary of State. As a result:

- all common shareholders of Black Hills Corporation became shareholders of Black Hills Holding Corporation, the holding company;
- Black Hills Corporation became a wholly-owned subsidiary of Black Hills Holding Corporation;
- Black Hills Corporation changed its name to "Black Hills Power, Inc." and the holding company changed its name to "Black Hills Corporation."

The formation of our holding company structure allows us to pursue, through separate subsidiaries, business opportunities in both regulated and unregulated markets.

Industry Overview

In the last decade, many U.S. regulatory bodies have taken steps to transform the energy sectors which they regulate to encourage competition, introduce customer choice and, in some cases, to improve the operational performance of strategic energy assets. In particular, the electric power industry is undergoing substantial change as a result of regulatory initiatives at the federal and state levels. As early as the mid-1990's, new regulatory initiatives to increase competition in the domestic power generation industry had been adopted or were being considered at the federal level and by many states. The primary focus of such efforts was to increase competition through the disaggregation of the traditional utility functions of generation, transmission, distribution and marketing of electricity into competitive or partially regulated businesses. This resulted in new investment opportunities to enter previously non-competitive or closed markets.

In 1992, the Federal Energy Regulatory Commission (FERC) issued Order 636, followed by Order 888 in 1996, to increase competition by easing entry into natural gas and electricity markets. These orders require owners and operators of natural gas and power transmission systems to make transmission service available on a non-discriminatory basis to energy suppliers. In order to better assure competitive access to the transmission network on a non-discriminatory basis, FERC issued Order 2000 in December 1999, which encourages electric utilities with power transmission assets to voluntarily form regional transmission organizations to provide regional management and control of transmission assets independent of firms that sell electricity.

The electric power industry has also witnessed growing consumer demand and increasingly frequent regional shortages of electricity over the past three years. The summers of 1998, 1999 and 2000 and the winter of 2000-2001 have all been characterized by very high peak prices for electricity in a number of recently created wholesale electricity markets. We believe that substantial amounts of new electric generating capacity need to be built to relieve shortages of electricity and to replace inefficient and obsolete facilities.

The oil and gas industry has experienced strong increases in commodity prices since the historically low levels experienced in 1998. These price increases have been driven in part by several years of modest drilling activity combined with strong growth in demand for energy commodities. Continued growth of the Internet and other high technology industries is contributing to increasing demand for power. Demand for natural gas is expected to remain strong as an increasing number of gas-fired power plants are brought into service.

The telecommunications industry is currently undergoing widespread changes brought about by, among other things, the Telecommunications Act of 1996, the decisions of federal and state regulators to open the monopoly local telephone and cable television markets to competition and the need for higher speed, higher capacity networks to meet the increasing consumer demand for expanded telecommunications services, including broader video choices and high speed data and Internet services. The convergence of these trends and the inherent limitations of most existing networks have created opportunities for new types of communications companies capable of providing a wide range of voice, video and data services through new and advanced high speed, high capacity telecommunications networks.

As a result of historical and anticipated regulatory initiatives and the increasing demand for electricity, fuel and broadband services, we believe there are significant opportunities for the development and growth of our independent energy businesses, our regulated utility and our communications business.

Strategy

Our strategy is to build long-term shareholder value by deploying our development, operating and marketing expertise in the deregulating energy industry. We plan to operate a mix of unregulated independent energy and regulated utility businesses, with emphasis on the independent power generation and fuel production segments. We expect our independent energy businesses to operate nationwide, with an integrated regional emphasis on the western half of the United States. Our utility and communications businesses intend to continue focusing their retail operations primarily on the northern Black Hills region of South Dakota, with wholesale power sales concentrated primarily in the Rocky Mountain and West Coast regions.

Our strategy includes the following key elements:

- grow our independent power unit by developing and acquiring power projects nationwide, focusing primarily in the western United States, where demand is currently strong and expected to grow;
- expand the generating capacity of our existing sites through a strategy known as "brownfield development;"
- sell a large percentage of the production from our newly developed projects through long-term contracts in order to secure attractive investment returns;
- increase our reserves of natural gas and crude oil and expand our fuel production;
- exploit our fuel cost advantages and our operating and marketing expertise to remain a low-cost power producer;
- manage the risks inherent in energy marketing by maintaining strict position limits that minimize price risk exposure and by conducting business with a diversified group of counterparties of high credit quality;
- build and maintain strong relationships with wholesale energy customers; and
- capitalize on our utility's established market presence, relationships and customer loyalty. We aim to expand our independent energy businesses and to increase our communications group's market penetration in our local service territory.

Grow our Independent Power Unit by Developing and Acquiring Power Projects Nationwide, Focusing Primarily in the Western United States, Where Demand is Currently Strong and Expected to Grow. Our aim is to tailor the development of power plants in regional markets based on prevailing supply and demand fundamentals and our existing fuel assets and fuel and energy marketing capabilities in order to capitalize on market growth while managing our fuel procurement needs. We believe the following trends will provide us with growth opportunities in the future:

- Demand for electricity will continue to outpace new generation capacity over the next several years, particularly in the Rocky Mountain and West Coast regions, resulting in continued strong electricity pricing.
- New electric generation construction will be predominantly gas-fired, which may create further competitive cost advantages for new and existing coal-fired generation assets.
- Significant expansion of gas-fired generation anticipated over the next several years will favor a balanced portfolio of generation assets, including coal-fired and hydroelectric generation.
- Transmission construction will significantly lag new generation development, favoring new development located near load centers or existing, unconstrained transmission locations.
- Disaggregation of the electric utility industry from traditionally vertically integrated utilities into separate generation, transmission, distribution and marketing entities will continue, thereby creating opportunities for acquisitions and joint ventures.

Over the next few years, we intend to grow through a combination of disciplined acquisitions and development of new power generation facilities primarily in the Rocky Mountain region where we believe we have the detailed knowledge of market fundamentals and competitive advantage to maintain profitable operations.

Expand the Generating Capacity of our Existing Sites Through a Strategy Known as "Brownfield Development." We believe that existing sites with opportunities for brownfield expansion generally offer the potential for greater returns than development of new sites through a "greenfield" strategy. Brownfield sites typically offer several competitive advantages over greenfield development, including:

- proximity to existing transmission systems;
- operating cost advantages related to ownership of shared facilities; and
- a less costly and time consuming permitting process.

We are currently expanding our capacity with brownfield development underway at our Arapahoe, Valmont and Wyodak sites, and believe that our Fountain Valley and Wyodak sites in particular provide further opportunities for a significant expansion of our gas- and coal-fired generating capacity over the next several years.

Sell a Large Percentage of the Production From our Newly Developed Projects Through Long-Term Contracts in Order to Secure Attractive Investment Returns. Recent extreme price volatility in the short-term power markets are resulting in greater demand among our wholesale customers for mid- and long-term power purchase agreements. By selling the majority of our energy and capacity under mid- and long-term contracts, we believe that we can satisfy the requirements of our customers while earning more stable revenues and greater returns over the long term than we could by selling our energy into the more volatile spot markets.

We also believe that the anticipated trend toward expansion of gas-fired generation over the next few years will favor gas-fired generation assets that are tied to tolling agreements or other arrangements where fuel cost and output prices are effectively secured. In recent months, we have entered into long-term tolling agreements covering nearly all of the gas-fired energy and capacity our independent power unit is adding through brownfield expansion of the Arapahoe and Valmont sites and from the Fountain Valley project. See "--Independent Power Plants."

Increase our Reserves of Natural Gas and Crude Oil and Expand our Fuel Production. We aim to support the fuel requirements of our growing portfolio of power plants as well as power plants owned by others. Our strategy is to continue increasing natural gas, coal and oil production levels while growing our reserve base for natural gas and oil. We expect to emphasize natural gas and coal production for potential direct or indirect use in the overall fuel strategy for our power plants. Our objective is to maintain coal reserves to serve our mine-mouth coal-fired generation plants directly, and to maintain sufficient natural gas production either to directly serve or indirectly hedge the fuel cost exposure of our gas-fired generation plants. Specifically, we plan to:

- target an oil and gas reserve replacement ratio of 125 percent and minimize exploration risk by focusing on lower-risk exploration and development drilling as well as acquisitions of proven producing properties;
- exploit our belief that the long-term demand for natural gas will remain strong by emphasizing natural gas, rather than oil, exploration and development drilling activities;
- add natural gas reserves and increase production by focusing on various shallow gas plays in the northern Rocky Mountain region, where the added production can be integrated with our fuel marketing and/or power generation activities;
- increase coal production and sales from our Wyodak mine by continuing to promote and develop additional mine-mouth generating facilities at the site, including the Wygen I plant, which is scheduled for completion in Spring 2003; and
- pursue future sales of coal from the Wyodak mine to rail-served customers by reducing the moisture content of our coal so that we can ship it greater distances.

Exploit our Fuel Cost Advantage and our Operating and Marketing Expertise to Remain a Low-Cost Power Producer. We expect to expand our portfolio of power plants having relatively low marginal costs of producing energy and related products and services. We intend to utilize a low-cost power production strategy, together with access to coal and natural gas reserves, to protect our revenue stream as an increasing number of gas-fired power plants are brought into operation. Low marginal production costs can result from a variety of factors, including low fuel costs, efficiency in converting fuel into energy, and low per unit operation and maintenance costs. We have aggressively managed each of these factors to achieve very low production costs, especially at our coal-fired and hydroelectric generating facilities.

Our primary competitive advantage is our coal mine, which is located in close proximity to our retail service territory. We are exploiting the competitive advantage of this native fuel source by building additional mine-mouth coal-fired generating capacity. This strengthens our position as a low-cost producer since transportation costs often represent the largest component of the delivered cost of coal.

Manage the Risks Inherent in Energy Marketing by Maintaining Strict Position Limits that Minimize Price Risk Exposure and by Conducting Business with a Diversified Group of Counterparties of High Credit Quality. Our fuel marketing operations require effective management of price, counterparty and operational risks. To mitigate these risks, we have implemented risk management policies and procedures for each of our marketing companies that prohibit speculative strategies and establish price risk exposure levels, counterparty credit limits and committees to monitor compliance with our policies. We also limit exposure to energy marketing risks by maintaining separate credit facilities for each of our marketing companies and by avoiding the issuance of parent company performance guarantees to counterparties of our marketing companies.

Build and Maintain Strong Relationships with Wholesale Energy Customers. We seek to sell a majority of our power under contracts with terms ranging from one to 10 or more years. Therefore, we strive to build strong relationships with utilities, municipalities and other wholesale customers, including the companies that sell us their power plants. We believe that these entities will continue to be the primary providers of electricity to retail customers in a deregulated environment and that they will need products, such as capacity, in order to serve their customers reliably. By providing these products to meet our customers' energy needs, we believe that we can earn more stable revenues and greater returns over the long term than we could by selling energy into the more volatile spot markets.

We have been successful in entering into a variety of wholesale contracts based on the specific needs of our customers. For example, in 1999, Public Service Company of Colorado approached us to take over ownership and construction of the 120 megawatt Arapahoe and Valmont facilities in Colorado. Public Service Company of Colorado was subject to regulatory constraints that restricted their ability to own the facilities and needed the plants completed in an efficient and timely manner to meet the rapid growth in demand. We completed construction of the facilities on schedule, and signed tolling agreements with Public Service Company of Colorado for the capacity and energy. In 2000, we signed agreements to expand the Arapahoe and Valmont facilities by 90 megawatts with 40 megawatts to be in service in 2001 and 50 megawatts to be in service in 2002. In addition, we recently acquired 240 megawatts at the Fountain Valley site in Colorado which we expect to be in service in 2001. We have signed tolling agreements with Public Service Company of Colorado for the expanded facilities and the Fountain Valley site.

Capitalize On Our Utility's Established Market Presence, Relationships and Customer Loyalty. We aim to expand our independent energy businesses and to increase our communications group's market penetration in our local service territory. As a result of its firmly established market presence, our electric utility has built solid brand recognition and customer loyalty in the Black Hills region. By ensuring a reliable supply of power to retail customers in our South Dakota and Wyoming service territory at rates substantially below the national average, we have also developed a strong, supportive relationship with our utility regulators.

Our utility provides a solid foundation of support for the expansion of our independent energy and communications businesses. In addition, industry, technical and market expertise from our utility supports the growth of our independent energy businesses, and our strong brand recognition assists us in achieving rapid customer acceptance of our bundled communications services in our Black Hills service territory.

Independent Energy

Our independent energy group engages in the production and sale of electric power through ownership of a diversified portfolio of generating plants, the production of coal, natural gas and crude oil primarily in the Rocky Mountain region, and the marketing of fuel products nationwide. The independent energy group was our primary source of revenue and net income growth in 2000 and the net income from the independent energy group is expected to exceed net income from our regulated utility beginning in 2001. The independent energy group consists of three units: independent power production, fuel production and fuel marketing.

Independent Power Production. Our independent power production segment acquires, develops and expands unregulated power plants. We currently operate under two business units - Black Hills Generation and Black Hills Energy Capital. In 1999, Black Hills Generation entered into a Construction Agency Agreement with Wygen Funding, L.P. (Funding) to act as Funding's agent in the construction of Wygen I, a 90 megawatt mine-mouth coal-fired plant. In the Construction Agency Agreement, Black Hills Generation agreed to enter into an Agreement for Lease and Lease for the Wygen I plant. The plant is expected to be completed in spring 2003. Black Hills Energy Capital was formed as a result of our acquisition of Indeck Capital Inc. in July 2000. The Indeck Capital acquisition provided us varying interests in operating independent power plants in California, New York, Massachusetts and Colorado with a total net ownership of 210 megawatts, as well as minority interests in several power-related funds with a net ownership interest of 40 megawatts.

In February 2001, we signed a definitive agreement with Enron Corporation to purchase 100 percent of an independent power project under construction near Colorado Springs, Colorado, known as the "Fountain Valley" project. We expect to close this transaction on or about March 31, 2001. This site will initially house 240 megawatts of gas-fired peaking facilities. The energy and capacity generated by the Fountain Valley project will be sold to Public Service Company of Colorado under a tolling contract expiring in July 2012 pursuant to which we assume no fuel cost or electricity market risk. We expect the plant to be completed in phases beginning in June 2001 and ending in July 2001 with the total cost expected to approximate $175 million. In addition to the current project, we believe that the Fountain Valley site provides us with attractive expansion and integration opportunities and is well-situated to serve other markets in the Rocky Mountain and southwest regions.

In addition to Wygen I and the Fountain Valley development, other projects under construction include:

- Arapahoe CC5, a 50 megawatt combined cycle expansion of our gas-fired turbines at the Arapahoe site located in the Front Range of Colorado;

- Valmont Unit 8, a 40 megawatt gas-fired turbine addition to our Valmont site located in the Front Range of Colorado;

- Black Hills Generation Gillette CT, a 40 megawatt gas-fired facility located at the same site as our Wygen I plant; and

- Harbor Expansion, a 30 megawatt (10 megawatt net ownership interest) expansion of our Harbor Cogeneration facility located in Wilmington, California.

In March 2001, we purchased a 40 megawatt turbine that will be located either adjacent to our Wygen I and Black Hills Generation Gillette CT plants near Gillette, Wyoming, or adjacent to our transmission system in Rapid City, South Dakota. The power plant to be constructed is currently known as the Lange project.

We strive to maintain diversification and balance in our portfolio of regulated and unregulated power plants. Our portfolio (including plants currently operating and those under construction) is diversified in terms of fuel mix and geographic location, with 79 percent of net unregulated capacity being gas-fired, 13 percent coal-fired, and the remainder hydroelectric. Our independent power plants are located in California, Wyoming, South Dakota, Colorado, New York and Massachusetts. In contrast, our electric utility capacity is approximately 53 percent coal-fired, 33 percent oil or gas-fired, and 14 percent under purchased power contracts, with plants located in South Dakota and Wyoming.

We also have a diversified mix of revenue sources. We typically sell two types of products: energy and capacity, including ancillary services. Although these are separate products, both are typically sold together. Energy refers to the actual electricity generated by our facilities for ultimate transmission and distribution to consumers of electricity. Energy is the only one of our products that is subsequently distributed to consumers. Capacity refers to the physical capability of a facility to produce energy. Ancillary services generally are capacity support products used to ensure the safe and reliable operation of the electric power supply system. Examples of ancillary services include:

- automatic generation control, which is used to balance energy supply with energy demand, referred to in our industry as "load," on a real-time basis; and

- operating reserves, which are used on an hourly or daily basis to generate additional energy if demand increases or if major generating resources go off-line or if transmission facilities become unavailable.

Our output is sold under contracts of varying length and subject to merchant pricing, thereby allowing us to take advantage of current favorable price trends, while hedging the impact of a potential downturn in prices in the future. We currently sell energy and capacity under a combination of short- and long-term contracts as well as direct sales into the merchant energy markets. Currently, we sell 70 percent to 80 percent of our unregulated generating capacity in operation under contracts greater than one year in duration. We sell the remainder of this capacity under short-term contracts or directly into the merchant markets. The energy and capacity generated by our Arapahoe and Valmont projects, and the additional energy and capacity expected at these sites and at our Fountain Valley project upon its completion, are subject to long-term tolling agreements with Public Service Company of Colorado. Similarly, the electricity generated by the Adirondack Hydro facilities in New York is under a combination of short- and long-term agreements with Niagara Mohawk.

How We Develop and Acquire Power Plants. We plan to actively pursue power plant acquisitions and development opportunities in areas we view as attractive. Our recent emphasis has been in the North American Reliability Council region known as the Western Systems Coordinating Council, or "WSCC." However, we anticipate that future acquisition and development activities will take place throughout North America. Among those factors we consider critical in evaluating the relative attractiveness of new generation opportunities are the following:

- electric demand growth potential in the targeted region;
- requirements for permitting and siting;
- proximity of the proposed site to high transmission capacity corridors;
- fuel supply reliability and pricing;
- the local regulatory environment; and
- the potential for geographic concentration of new generation with our existing power plant portfolio.

We intend to target both acquisition and development opportunities which provide a minimum expected return on equity of 12 to 13 percent. We plan to emphasize development projects over acquisitions, since we believe they generally offer opportunities for higher rates of return.

Our goal is to sell approximately 80 percent of the independent power generation portfolio under long term contracts, while leaving the remainder available for merchant, or "spot" sales. We aim to secure long-term power sales contracts in conjunction with non-recourse plant financing. This enables us to design a debt repayment schedule to closely match the term of the power sales contracts, so that at the end of the contract term, there is little or no debt left to be serviced.

Independent Power Plants

General. Power facilities are often classified by cost of production. Facilities that have the lowest costs of production relative to other power plants in the region are usually the facilities that are first used to provide energy. These facilities are known as "baseload" utilities and typically operate more than 60 percent of the time they are available. Our hydroelectric assets in New York and our coal-fired plants in Wyoming are examples of low-cost, baseload plants.

As demand for electricity rises during the year or even during the course of a day, power plants that have higher costs of production are dispatched to supply additional energy. Facilities that regularly provide additional energy during a day are known as "intermediate" facilities. Facilities which are used between 10 percent and 60 percent of the time they are available are typically considered to be intermediate facilities.

Power plants with the highest costs of production are called upon only in times of exceptionally high demand and are known as "peaking units." Peaking units are generally dispatched less than 10 percent of the time they are available.

Rocky Mountain and West Coast Facilities. We own approximately 151 megawatts of generating capacity in the WSCC states of California and Colorado, and are in the process of constructing or acquiring another 470 megawatts in the region. All of these facilities in operation are gas-fired, with all but our Harbor Cogeneration facility in California operating under long-term power purchase or tolling agreements. The Harbor Cogeneration facility, our primary operating facility in California, operates as a merchant peaking plant selling ancillary services and energy into the California market.

We are currently implementing an extensive expansion and development effort in the region. In February 2001, we entered into an agreement to purchase a 240 megawatt gas-fired facility near Colorado Springs, Colorado, which is scheduled to be completed in phases beginning in May 2001. We have also begun construction on the expansion of our Arapahoe and Valmont facilities in Colorado, with long-term tolling contracts already in place for the sale of capacity and energy. An additional 130 megawatts of generating capacity is under construction adjacent to our coal mine in Gillette, Wyoming. See "--WSSC Facilities," below. We are expanding our Harbor Cogeneration facility by adding two efficient exhaust heat turbines, which will add 30 megawatts (10 megawatts net ownership interest) of generation capacity. We have entered into an agreement to sell the summer peaking capacity of this facility under a three-year arrangement with the California Independent System Operator, or "CAISO." We expect to sell the remaining capacity and all of the energy on a merchant basis into the California market.

WSCC Facilities

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
In Operation:						
Arapahoe Unit 5	Gas	CO	40.0	100%	40.0	2000
Arapahoe Unit 6	Gas	CO	40.0	100%	40.0	2000
Valmont Unit 7	Gas	CO	40.0	100%	40.0	2000
Ontario	Gas	CA	12.0	50%	6.0	1984
Harbor	Gas	CA	80.0	31.8%	25.4	1989
Total in Operation			212.0		151.4	
Under Construction:						
Fountain Valley	Gas	CO	240.0	100%	240.0	2001
Arapahoe CC5	Gas	CO	50.0	100%	50.0	2002
Valmont Unit 8	Gas	CO	40.0	100%	40.0	2001
Wygen #1	Coal	WY	90.0	100%	90.0	2003
BHG Gillette CT	Gas	WY	40.0	100%	40.0	2001
Harbor Expansion	Gas	CA	30.0	31.8%	9.5	2001
Total in Construction			490.0		469.5	
Total WSCC			702.0		620.9	

Arapahoe, Valmont and Fountain Valley Facilities

In Operation: Our Arapahoe and Valmont plants are wholly-owned gas-fired peaking facilities in the Front Range of Colorado, with a total capacity of 120 megawatts. The projects were acquired from Public Service Company of Colorado in January 2000 jointly by the former Indeck Capital and us, and were put into service on June 1, 2000. We sell all of the output from these plants to Public Service Company of Colorado under tolling contracts expiring in May 2012. These contracts also cover the Fountain Valley project and the Arapahoe and Valmont expansion projects described below.

Under Construction: We expect to increase our capacity by 40 megawatts at the Valmont project by May 2001 and by 50 megawatts at the Arapahoe plant by May 2002.

The first phase of our 240 megawatt gas-fired Fountain Valley facility is scheduled for completion in May 2001, with final completion scheduled for July 2001. The Fountain Valley site, located in Colorado has ample capacity for subsequent expansion if market conditions prove to be attractive.

Wygen I Facility

The Wygen I facility will be a leased mine-month coal-fired plant with a total capacity of 90 megawatts, which is expected to be completed by spring 2003. The Wygen I plant will be substantially identical in design to our electric utility's Neil Simpson II facility, completed in 1995. The two plants will both run on pulverized low-sulfur coal fed by conveyor from our adjacent Wyodak mine. The plant will burn approximately 500,000 tons of coal per year, and will use the latest available environmental control technology. We intend to sell the majority of the power from the facility under long-term unit contingent capacity and energy sales contracts, under which delivery is not required during unplanned plant outages. We have entered into a contract to sell 60 megawatts of unit contingent capacity from this plant to Cheyenne Light, Fuel and Power Company with a term of 10 years from the date the plant becomes operational. We have also signed a contract to sell an additional 20 megawatts of unit contingent capacity and energy to the Municipal Electric Agency of Nebraska for a term of 10 years.

Black Hills Generation Gillette CT

The Black Hills Generation Gillette CT facility, a gas-fired combustion turbine facility located at the same site as our Wygen I facility, has a total capacity of 40 megawatts and is scheduled to be completed in May 2001. We plan to utilize this facility as a merchant plant through summer 2001. Beginning in September 2001, we will sell the energy and capacity from this facility to Cheyenne Light, Fuel and Power Company under a 10-year unit contingent tolling agreement.

Ontario Cogeneration Facility

Ontario Cogeneration Company is a 12 megawatt, gas-fired power plant in Ontario, California, which is currently being operated as a baseload plant. The project is selling all of this electrical facility's steam to Sunkist Growers, Inc. Output from the plant is also subject to a 25-year power purchase agreement with Southern California Edison expiring in January 2010. For a description of certain issues relating to our operation of this plant and our agreement with Sunkist Growers, Inc., see "--Regulation--Environmental Regulation--Clean Air Act."

Harbor Cogeneration Facility

In Operation: Harbor Cogeneration, a gas-fired plant located in Wilmington, California, is currently being operated as a merchant peaking plant selling ancillary services and energy into the CAISO market. It formerly operated under a 30-year power purchase agreement with Edison Mission Energy. This contract was terminated in February 1999 under a settlement agreement with Southern California Edison. Under the buyout agreement, Harbor Cogeneration will receive payments pursuant to a termination payment schedule for an amount equal to the total payment under the original contract due for the 11-year period beginning April 1, 1997 and ending on October 1, 2008. The facility currently has no long-term debt outstanding.

Under Construction/Expansion: We are currently expanding the Harbor Cogeneration plant by an additional 30 megawatts (10 megawatt net ownership interest), with a targeted completion date of May 2001. The summer peaking capacity from this plant will be made available to CAISO beginning in May 2001 and ending in May 2003. We plan to sell the remaining capacity and all of the energy from this plant in the California market on a merchant basis.

Lange Project

In March 2001, we purchased a 40 megawatt gas-fired combustion turbine which will be located either adjacent to our Wygen I and Black Hills Generation Gillette CT plants near Gillette, Wyoming, or at a new site adjacent to our transmission system in Rapid City, South Dakota, where we have received all necessary permits for the construction of two 40 megawatt combustion turbine facilities.

Northeast Facilities. We currently own approximately 58 net megawatts of generation capacity in eight plants in the Northeast region, all of which are located in New York and Massachusetts. Sixty-seven percent of this generation is "run-of-river" hydroelectric, with the remainder being gas-fired peaking capacity. We currently do not have any plans for repowering or expanding any of these facilities.

The Massachusetts plant sells energy and capacity under annual contracts. Four of our New York plants will begin selling all or a significant portion of energy and capacity competitively into the New York Power Pool shortly upon expiration of their existing five-year power sales contracts. The remaining three New York plants, Hudson Falls, South Glens Falls and Middle Falls, are currently operating under long-term power purchase agreements with Niagara Mohawk.

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
Northeast						
New York State Dam	Hydro	NY	11.4	100%	11.4	1990
Middle Falls	Hydro	NY	2.3	50%	1.2	1989
Sissonville	Hydro	NY	3.0	100%	3.0	1990
Warrensburg	Hydro	NY	2.9	100%	2.9	1988
Hudson Falls	Hydro	NY	41.9	30.2%	12.7	1995
South Glens Falls	Hydro	NY	13.9	30.2%	4.2	1994
Fourth Branch	Hydro	NY	3.4	100%	3.4	1988
Pepperell	Gas	MA	40.0	48.7%	19.5	1990
Total (Northeast)			118.8		58.3	

Adirondack Hydro Development

The seven "run-of-river" hydroelectric plant interests acquired as a result of our acquisition of Indeck Capital are:

- New York State Dam, an 11.4 megawatt plant located in Waterford and Cohoes, New York;
- Middle Falls, a 2.3 megawatt plant located in Easton, New York;
- Sissonville, a 3.0 megawatt plant located in Potsdam, New York;
- Warrensburg, a 2.9 megawatt plant located in Warrensburg, New York;
- Hudson Falls, a 41.9 megawatt plant located in Moreau, New York;
- South Glens Falls, a 13.9 megawatt plant located in South Glens Falls, New York; and
- Fourth Branch, a 3.4 megawatt plant located in Waterford, New York.

We acquired approximately 10 percent of the Hudson Falls and the South Glen Falls plants as part of the Indeck Capital acquisition and an additional 20 percent of these plants in December 2000. These projects run at a high capacity factor because the Hudson River is regulated for power generation and flood control.

The seven projects were initially covered by long-term power purchase contracts with Niagara Mohawk for all or most of their output. Currently, three projects have been restructured to allow the power purchase contracts to be bought out and for us eventually to sell power into the New York Independent System Operator (NY-ISO). The New York State Dam, Sissonville, Fourth Branch and Warrensburg facilities are currently subject to short-term transition power sales agreements expiring over the next two to three years, at which point these plants will sell directly into the market on a merchant basis.

Pepperell Facility

The Pepperell facility is a 40 megawatt gas-fired combined-cycle plant located in Pepperell, Massachusetts. The plant is currently subject to a tolling agreement with Enron Power and Trading for the sale of a majority of its energy for the year 2001, and a steam sales agreement with the Pepperell Paper Company expiring in November 2001.

Power Funds. In addition to our ownership of the power plants described above, we hold various indirect interests in power plants through our investment in energy and energy-related funds, both domestic and international, as described below:

Fund Name	Total Amount ($MM)	Left to be Funded ($MM)	Number of Plants	Total Capacity (MWs)	Interest	Net Capacity (MWs)
Energy Investors Fund I	$159.5	$0	7	136.0	12.6%	17.1
Energy Investors Fund II	$115.0	$0	6	130.0	6.9%	9.0
Project Finance Fund III	$101.0	$0	7	239.0	5.3%	12.7
Caribbean Basin	$75.0	$60	1	34.0	3.7%	1.2
Total Fund Interests				539.0		40.0

Financing of our Independent Power Projects. We have financed our principal independent power generation facilities primarily with non-recourse debt that is repaid solely from the project's revenues. This type of financing is referred to as "project financing." These financings generally are secured by the physical assets, major project contracts and agreements, cash accounts and, in certain cases, our ownership interest, in the related project. True project financing is not available for all projects, including some assets purchased out of bankruptcy, some merchant plants and some purchases of minority stock positions in publicly-traded companies. Even in those instances, however, we may still be able to finance a smaller portion of the total cost with project financing, with the remainder financed with debt that is either raised or supported at the corporate rather than the project level.

Project financing transactions generally are structured so that all revenues of a project are deposited directly with a bank or other financial institution acting as escrow or security deposit agent. These funds then are payable in a specified order of priority set forth in the financing documents to ensure that, to the extent available, they are used first to pay operating expenses, senior debt service and taxes and to fund reserve accounts. Thereafter, subject to satisfying debt service coverage ratios and certain other conditions, available funds may be disbursed for management fees or dividends or, where there are subordinated lenders, to the payment of subordinated debt service.

These project financing structures are designed to prevent the lenders from looking to us or our other projects for repayment; that is, they are "non-recourse" to us and our affiliates not involved in the project, unless we or another affiliate expressly agree to undertake liability. In the event of a foreclosure after a default, our project affiliate owning the facility would only retain an interest in the assets, if any, remaining after all debts and obligations were paid. In addition, the debt of each operating project may reduce the liquidity of our equity interest in that project because the interest is typically subject both to a pledge securing the project's debt and to transfer restrictions set forth in the relevant financing agreements. Also, our ability to transfer or sell our interest in certain projects or the project's power is restricted by certain purchase options or rights of first refusal in favor of our partners and certain change of control restrictions in the project financing documents.

Fuel Production

Coal

Our coal production segment mines and processes low-sulfur sub-bituminous coal near Gillette, Wyoming. The Wyodak mine, which we acquired in 1956 from Homestake Gold Mining Company, sits on top of the Powder River Basin, one of the largest coal reserves in the United States. We believe the Wyodak mine is the oldest operating surface coal mine in the nation, with an annual production of approximately three million tons. Mining rights to the coal are based on four federal leases and one state lease. We pay royalties of 12.5 percent and 9.0 percent, respectively, of the selling price on all federal and state coal. As of December 31, 2000, we had coal reserves of 275 million tons, enough to satisfy present contracts for over 90 years. Substantially all of our coal production is sold under long-term contracts to Black Hills Power, Inc., our electric utility, and to Pacific Power & Light (Pacific Power).

Our coal segment's agreement with Black Hills Power limits earnings from all coal sales to Black Hills Power to a specified return on our original cost depreciated investment base. Black Hills Power made a commitment to the South Dakota Public Utilities Commission, the Wyoming Public Service Commission and the City of Gillette that coal would be furnished and priced as provided by that agreement for the life of our Neil Simpson II plant.

The price for unprocessed coal sold to Pacific Power for its 80 percent interest in the Wyodak Plant is determined by a coal supply agreement terminating in 2013. For a description of litigation with the parent company of Pacific Power relating to this agreement, see "ITEM 3. LEGAL PROCEEDINGS - PacifiCorp Litigation."

In May 2000, we acquired the K-Fuel plant, a coal enhancement plant located near our Gillette, Wyoming coal mine. The plant, which transforms high-moisture, low-heat-value coal into low-moisture, high-heat-value coal, is currently not in service. We are working in conjunction with Denver-based KFx, Inc. to attract investors to make the capital improvements necessary to re-start the plant. If we do not locate suitable investment partners, the plant will not be re-started.

Over the next several years, we expect to increase coal production to supply:

- the Wygen I 90 megawatt mine-mouth power plant, which is scheduled for completion in 2003; and
- additional mine mouth generating capacity of up to 500 megawatts at the same site, which is in the early stages of development.

In addition, if our K-Fuel plant is re-started, we expect to increase production from the Wyodak mine and market any lower moisture, higher heat content coal we produce to an expanded customer base.

Natural Gas and Crude Oil

Our oil and gas exploration and production segment operates approximately 298 oil and gas wells, all of which are located in Wyoming. The majority of these wells are in the Finn-Shurley Field area, located in Weston and Niobrara Counties in Wyoming. We also own a working interest in, but do not operate, an additional 341 wells located in California, Montana, North Dakota, Texas, Wyoming, Oklahoma and offshore in the Gulf of Mexico. In addition, we have accumulated significant acreage in other northern Rocky Mountain region, which we plan to utilize for oil and gas exploration.

We plan to target a reserve replacement ratio equal to 125 percent of annual production while minimizing exploration risk by focusing on development drilling and relatively low-risk exploration opportunities as well as acquisitions of producing properties. A key component of this strategy is the pursuit of shallow gas opportunities in the northern Rocky Mountain region. We also expect to modestly increase our California and offshore production in the future, but do not plan to serve as the operator for such production activities.

As of December 31, 2000, we had proved reserves of 4.4 million barrels of oil and 18.4 billion cubic feet of natural gas, with approximately 62 percent of current production consisting of natural gas. In 2000, our oil and gas production increased 12 percent over 1999 levels, with record drilling results and year-end reserves.

In March 2001, we signed a definitive agreement to purchase certain operating and non-operating interests in 74 oil and gas wells located primarily in Colorado and Wyoming. This transaction is expected to close in April 2001. These properties have proved reserves of approximately 8.7 billion cubic feet of natural gas and approximately 200,000 barrels of oil, representing an increase in our existing proved reserves of over 20 percent.

Fuel Marketing. We market natural gas, oil and coal in specific regions of the United States. We offer physical and financial wholesale fuel marketing and price risk management products and services to a variety of customers. These customers include natural gas distribution companies, municipalities, industrial users, oil and gas producers, electric utilities, coal mines, energy marketers and retail gas users. Our fuel marketing businesses collectively have 35 employees. Our average daily marketing volumes for the year ended December 31, 2000, were 860,800 million British thermal units of gas, 44,300 barrels of oil and 4,400 tons of coal.

The following table describes the location of our fuel marketing operations and sales offices:

Company	Fuel	Marketing Operations	Sales Offices
Enserco Energy	Natural Gas	Golden, CO	Chicago, IL; Calgary, Alberta, Canada
Black Hills Energy Resources	Crude Oil	Houston, TX	Tulsa, OK; Midland, TX; Longview, TX
Black Hills Coal Network	Coal	Mason, OH	St. Clairsville, OH

Gas Marketing

Our natural gas marketing operations are headquartered in Golden, Colorado, with satellite offices in Calgary, Canada and Chicago, Illinois. Our gas marketing operations focus primarily on wholesale marketing and producer marketing services. Producer services include providing for direct purchases of wellhead gas and for risk transfer and hedging products. Our gas marketing efforts are concentrated in the Rocky Mountain and Pacific Coast regions and in Western Canada. We contractually hold natural gas storage capacity and both long and short-term transportation capacity on several major pipelines in the western United States and Canada. We utilize this capacity to move relatively low cost natural gas from the producer regions to more expensive end-use market areas.

Oil Marketing and Transportation

Our crude oil marketing and transportation operations are concentrated primarily in Texas, Oklahoma, Louisiana and Arkansas. In July 1999, we acquired a 33 percent ownership interest in a 200-mile pipeline, with a capacity of 67,000 barrels per day, that transports foreign crude oil from Beaumont, Texas north to refining and trading markets.

Coal Marketing

We market coal to various industrial customers and power plants located primarily in the midwest and eastern regions of the United States through our coal marketing subsidiary, Black Hills Coal Network. We formed Black Hills Coal Network in 1998 to acquire the assets and hire the operational management of Coal Network and Coal Niche, based in Mason, Ohio. These predecessor companies were coal brokerage and agency companies with customers located primarily east of the Mississippi River.

Electric Utility - Black Hills Power, Inc.

Our electric utility, Black Hills Power, is engaged in the generation, transmission and distribution of electricity. It provides a solid foundation of revenues, earnings and cash flow that support utility capital expenditures, dividends, and overall performance and growth.

Distribution and Transmission. Our electric utility distribution and transmission businesses serve 58,600 electric customers, with an electric transmission system of 447 miles of high voltage lines and 541 miles of lower voltage lines. Our utility's service territory covers a 9,300 square mile area of western South Dakota, eastern Wyoming and southeastern Montana with a strong and stable economic base. Over 90 percent of our utility's retail electric revenues are generated in South Dakota.

The following are characteristics of our distribution and transmission businesses:

- We have a diverse customer and revenue base. Our revenue mix in 2000 is comprised of 29 percent wholesale off-system sales, 26 percent commercial, 20 percent residential, 14 percent industrial, 10 percent contract wholesale and 1 percent municipal. Approximately 68 percent of our large commercial and industrial customers are provided service under long-term contracts. We have historically optimized the utilization of our power supply resources by selling wholesale power to other utilities and to power marketers in the spot market and through short-term sales contracts.

- In 1999, the South Dakota Public Utilities Commission extended our previous retail rate freeze for another five-years, through January 1, 2005. The rate freeze preserves our low-cost rate structure at levels below the national average for our retail customers while allowing us to retain the benefits from cost savings and from wholesale "off-system" sales, which are not covered by the rate freeze. This provides us with flexibility in allocating our generating capacity to maximize returns in changing market environments.

- Twenty-nine percent of our electric revenues for the year ended December 31, 2000 consisted of off-system sales compared to 8 percent in 1999 and 5 percent in 1998. Further increases in the volume of off-system sales are expected in the future due to demand growth in the Rocky Mountain regions, the June 2000 addition of 40 megawatts of gas-fired generating capacity and the availability of additional generation resources due to the scheduled closing of Homestake Mining's Black Hills operations at the end of 2001. We expect that the closing of Homestake Mining's operations will release over 100,000 megawatthours of energy per year, or approximately 4.3 percent of megawatthours sold by our utility in 2000.

- Our transmission system has the capability of connecting to either the midwestern or western transmission systems as a result of the recent completion of the "East Express" feeder line, which provides us with transmission access between the WSCC region and the Mid-Continent Area Power Pool, or "MAPP" region. This system allows us the opportunity to improve customer reliability and take advantage of power price differentials between the two electric grids. Our system allows us to transmit up to 80 megawatts of our generation into the MAPP. Alternatively, we can receive up to 20 megawatts of power from MAPP into our WSCC-based transmission system. We expect to increase this capability to 50 megawatts in 2001 through an upgrade of our transmission facilities at a cost of less than $1 million.

- We have firm transmission access to deliver up to 65 megawatts of power on Pacific Power's system to wholesale customers in the western region.

- On October 15, 2000, we indicated to FERC our intent to participate in a regional transmission organization (RTO). Our transmission system is a part of the western transmission grid governed by the Western Systems Coordinating Council, and it interconnects with transmission systems operated by Western Area Power Administration (WAPA) and by PacifiCorp. WAPA is evaluating participation in the Desert Star RTO which will involve transmission systems in Colorado and the southwest region, while PacifiCorp is evaluating participation in the RTO West which will involve transmission systems in Wyoming and the northwest region. Neither Desert Star RTO nor RTO West has been formally organized at this time, but we expect that Desert Star RTO and RTO West will be making their final FERC filings late this year or in early 2002. If FERC approves these two RTOs, the organizations anticipate being fully operational in late 2002. We will continue to monitor the development of these two RTOs and decide in the future which RTO best fits our transmission system and operations.

Power Purchase Agreements. Approximately 40 percent of our utility's current load is under long-term contracts. Our key contracts include a 10-year contract expiring in 2007 with Montana-Dakota Utilities Company for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory, and a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy. Both contracts are integrated into our control system and are treated as firm native load. In addition, we recently entered into an agreement with the Municipal Electric Agency of Nebraska for the sale of 30 megawatts of unit contingent energy and capacity for a period through the completion of construction of the Wygen I independent power facility, which is expected in spring 2003. For the 10-year period beginning with the completion of the Wygen I facility, our utility and our independent power unit will each provide 20 megawatts of unit contingent energy and capacity to the Municipal Electric Agency of Nebraska.

Our utility's electric load is served by coal-, oil- and natural gas-fired generating units providing 393 megawatts of generation capacity and from the following purchased power and capacity contracts with Pacific Power:

- a power sales agreement expiring in 2023, involving the purchase by us of 65 megawatts of baseload power in 2001, and scheduled to decline to 50 megawatts by 2004;
- a reserve capacity integration agreement expiring in 2012, which makes available to us 100 megawatts of reserve capacity in connection with the utilization of the Ben French CT units; and
- a capacity option call, which gives us an option to purchase up to 60 megawatts of peaking capacity seasonally through March 31, 2007.

Regulated Power Plants. Since 1995, our utility has been a net producer of energy. Our utility owns 393 megawatts of generating capacity, all of which is located in the Rocky Mountain region. Our utility's peak system load of 372 megawatts was reached in July 2000. None of our generation is restricted by hours of operation, thereby providing us with the ability to generate power to meet demand whenever necessary and feasible.

The following table describes our utility's portfolio of power plants:

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
Ben French	Coal	SD	25.0	100%	25.0	1960
Ben French Diesels 1-5	Diesel	SD	10.0	100%	10.0	1965
Ben French CTs 1-4	Gas/Oil	SD	100.0	100%	100.0	1977 1979
Neil Simpson I	Coal	WY	21.8	100%	21.8	1969
Neil Simpson II	Coal	WY	88.9	100%	88.9	1995
Osage	Coal	WY	34.5	100%	34.5	1948
Wyodak	Coal	WY	362.0	20%	72.4	1978
Neil Simpson CT	Gas	WY	40.0	100%	40.0	2000
Total			682.2		392.6	

Ben French

Ben French is a wholly-owned coal-fired plant situated in Rapid City, South Dakota, with a capacity of 25 megawatts. This plant was put into service in 1960 and has since been operating as a baseload plant. Coal for the plant is purchased from our Wyodak mine and delivered by truck.

Ben French Diesel Units 1-5

The Ben French Diesel Units 1-5 are wholly-owned diesel-fired plants located in Rapid City, South Dakota, with a capacity of 10 megawatts. These plants were put into service in 1965, and are being operated as peaking plants.

Ben French CT's 1-4

The Ben French Combustion Turbines 1-4 are wholly-owned gas and oil-fired units with a capacity of 100 megawatts located in Rapid City, South Dakota. These facilities were put into service from 1977 to 1979, and are being operated as peaking units.

Neil Simpson I and II

Neil Simpson I and II are air-cooled, coal-fired wholly-owned facilities located near Gillette, Wyoming. Neil Simpson I has a capacity of 21.8 megawatts and was put into service in 1969. Neil Simpson II has a capacity of 88.9 megawatts and was put into service in 1995. These plants are operated as baseload facilities, and are mine-mouth coal-supplied plants, receiving their coal directly from the Wyodak mine.

Osage

The Osage plant is a wholly-owned coal-fired plant in Osage, Wyoming with a total capacity of 34.5 megawatts and was put into service from 1948 to 1952. This plant has three turbine generation units, and is being operated as a baseload plant. Coal for the plant is purchased from our Wyodak mine and delivered by truck.

Wyodak

Wyodak is a 362 megawatt mine mouth coal-fired plant owned jointly by Pacific Power and us and in which we own a 20 percent (72.4 net megawatt) ownership interest. Our Wyodak mine furnishes all the coal fuel supply for the Wyodak plant. The plant was put into service in 1978, and is currently being operated as a baseload plant.

Neil Simpson CT

The Neil Simpson Combustion Turbine is a wholly-owned gas-fired plant located near Gillette, Wyoming with a capacity of 40 megawatts. This plant was put into service in 2000, and was installed to provide peaking capabilities.

Communications

Our communications group, known as Black Hills FiberCom, was formed to provide state-of-the-art broadband telecommunications services to the underserved markets of Rapid City and the northern Black Hills of South Dakota. We offer residential and business customers a full suite of telecommunications services, including local and long distance telephone service, expanded cable television service, cable modem Internet access and high speed data and video services. We have completed a 210-mile inter- and intra-city fiber optic network and currently operate 588 miles of two-way interactive hybrid fiber coaxial or "HFC" cable. We believe we are one of the first companies in the United States to provide video entertainment service, high-speed Internet access, and local and long distance telephone services over an advanced broadband infrastructure. We have bundled these services into value packages with a single consolidated bill for all of these services.

We introduced our broadband communications services to the Rapid City and northern Black Hills areas in November 1999. As of December 31, 2000, we had attracted 8,368 residential customers and 646 business customers. Our goal is to increase the number of our customers by more than two-fold, and to attain within our service territory 50 percent residential market penetration while serving 35 percent of all broadband business customers.

The build out of our communications network is approximately 70 percent complete and is expected to be completed in 2001. We estimate that completion of the build-out will require approximately $25 million in 2001.

Competition

The independent power, fuel production and fuel marketing industries are characterized by numerous strong and capable competitors, some of which may have more extensive operating experience, larger staffs or greater financial resources than us. In particular, the independent power industry in recent years has been characterized by increased competition for asset purchases and development opportunities.

In addition, Congress has considered various pieces of legislation to restructure the electric industry that would require, among other things, customer choice and/or repeal of the Public Utility Holding Company Act of 1935, or "PUHCA". The debate is likely to continue and perhaps intensify. The effect of enacting such legislation cannot be predicted with any degree of certainty. Industry deregulation may encourage the disaggregation of vertically integrated utilities into separate generation, transmission and distribution businesses. As a result of these potential regulatory changes, significant additional competitors could become active in the generation segment of our industry.

Our communications unit faces competition from numerous well established companies, including Qwest Communications, Rapid City's incumbent local exchange carrier, Midcontinent Communications, the area's incumbent cable television provider, as well as long distance providers and Internet service providers. Our success in this business will depend upon, among other things, the quality of our customer service, the willingness of residential and business customers to accept us as an alternative provider of broadband communications services, our products and services and our ability to offer an attractive package of bundled products.

Risk Management

Our fuel marketing operations require efficient risk management of price, counterparty performance and operational risks. Price risk is created through the volatility of energy prices. Counterparty performance risk is the risk that a counterparty will fail to satisfy its contractual obligations to us, and includes credit risk. Operational risk arises from a lack of internal controls. We have implemented controls to mitigate each of these risks.

Our fuel marketing operations are conducted in accordance with guidelines established through separate risk management policies and procedures for each marketing company and through our credit policy. These policies are established by our board of directors, reviewed on a regular basis and monitored as described below.

We maintain a working risk management committee for each of our marketing companies, and a credit committee at the parent company level. The risk management committees focus on implementation of risk management procedures and on monitoring compliance with established policies. The credit committee sets counterparty credit limits, monitors credit exposure levels and reviews compliance with established credit policies. Additionally, we employ a risk manager and a credit manager responsible for overseeing these functions.

Our risk management policies and procedures specify maximum price risk exposure levels that each respective marketing company must operate within. These policies and procedures establish relatively low exposure levels and prohibit speculative trading strategies.

As part of our enterprise-wide risk management strategy, we limit our exposure to energy marketing risks by maintaining separate credit facilities within each of our fuel marketing companies. These credit facilities have security interests solely against the assets of the respective marketing company, with the exception of a $1 million guarantee by our coal mining subsidiary. We do not currently issue parent company performance guarantees to counterparties of our marketing companies.

A significant potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. Short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risks, we restrict wholesale off-system sales to amounts by which our anticipated generation capabilities exceed our anticipated load requirements plus a required reserve margin. We further control this risk by selling only in the day-ahead power market and by entering into longer-term sales contracts that are made on a "unit contingent" basis, under which delivery is not required during unplanned outages at specified power plants.

California Markets

In 1996, California enacted legislation restructuring the state's investor-owned utilities. The legislation instituted a rate freeze on amounts that investor-owned utilities could charge their customers for the duration of a transition period also established by the legislation. The legislation did not make any provision for a California utility to recover costs of purchased electricity that exceeded the rates that could be charged under the rate freeze. Due to inadequate supplies of power and an unanticipated surge in demand, the California market has experienced rapid increases in electric power and natural gas prices. As a result, the state's two largest investor-owned utilities, Pacific Gas & Electric Company (PG&E) and Southern California Edison (SCE), have incurred costs of procuring power significantly in excess of their ability to recover those costs through authorized retail rates and have indicated that, unless the rate freeze is eliminated or other proposed relief is provided, they are, or shortly will, become insolvent.

We may experience losses related to the potential insolvency of the California utilities in the event that a utility defaults on its obligations:

- under its agreements with us;
- to the CAISO, which administers the real-time markets for energy and ancillary services, resulting in non-payment to us; or
- to other energy companies, causing those energy companies to default on their obligations to us.

We have two agreements with SCE involving our California independent power plants.

- In 1999, we entered into a settlement agreement with SCE involving our Harbor Cogeneration plant located in Wilmington, California, in which we own a 31.8 percent interest. The settlement agreement provides for the termination of a 30-year power purchase agreement in exchange for payments of approximately $4 million per year by SCE through October 2008.
- The cogeneration plant located in Ontario, California is entitled to receive energy and capacity payments from SCE of approximately $1.7 million per year, under a long-term contract expiring in 2010.

As of March 1, 2001, we had approximately $1.5 million of past due accounts receivable from SCE, with delinquencies ranging from 15 to 75 days in duration. We have no other material contractual relationships with SCE and no material agreements with PG&E.

The summer peaking capacity from the expansion of the Harbor Cogeneration plant will be sold to the CAISO beginning in May 2001 and ending in May 2003 under an agreement with the CAISO that provides for payments to us of $3 million per year for each of 2001, 2002 and 2003. We have no other agreements with the CAISO and do not otherwise sell capacity and energy directly into the California market either through long-term contracts or on a merchant basis. All other merchant sales are made to power marketers who in turn sell into the California market. In addition, our fuel production and fuel marketing exposure to the California market is primarily indirect through sales to creditworthy counterparties, including neighboring utilities and large, well-established gas marketing firms.

In recent months, the Governor of the State of California, representatives of the state legislature and numerous industry participants have undertaken several initiatives designed to address market disruptions in California. In February 2001, SCE reached a tentative agreement under which the state would pay $2.76 billion to purchase SCE's high voltage transmission system and SCE would drop a federal lawsuit in which it has sought authority to bill its customers for past unrecovered costs. Prior to its implementation, this agreement must be approved by the California state legislature. There is no assurance that any legislation will be enacted or that, if enacted, the sale of transmission assets will provide SCE with sufficient funds to pay any current or future obligations to us. In addition, there is no assurance that any current or future defaults by California utilities on obligations owed to others will not result in defaults by our counterparties. However, we believe that our direct exposure to potential defaults in the California market is largely limited to the agreements with SCE and the CAISO described above and that our indirect exposure is minimal.

Regulation

We are subject to a broad range of federal, state and local energy and environmental laws and regulations applicable to the development, ownership and operation of our projects. These laws and regulations generally require that a wide variety of permits and other approvals be obtained before construction or operation of a power plant commences and that, after completion, the facility operate in compliance with their requirements. We strive to comply with the terms of all such laws, regulations, permits and licenses and believe that all of our operating plans are in material compliance with all such applicable requirements.

Energy Regulation

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction are required to file rate schedules with FERC prior to commencement of wholesale sales or interstate transmission of electricity. Public utilities with cost-based rate schedules are also subject to accounting, record-keeping and reporting requirements administered by FERC.

The Energy Policy Act. The passage of the Energy Policy Act in 1992 further encouraged independent power production by providing certain exemptions from regulation for exempt wholesale generators or "EWGs." All of our subsidiaries that would otherwise be treated as public utilities are currently treated as EWGs under the Energy Policy Act. An EWG is an entity that is exclusively engaged, directly or indirectly, in the business of owning or operating facilities that are exclusively engaged in generation and selling electric energy at wholesale. An EWG will not be regulated under PUHCA, but is subject to FERC and state public utility commission regulatory reviews, including rate approval. Since EWGs are only allowed to sell power at wholesale, their rates must receive initial approval from FERC rather than the states. All of our EWGs to date that have sought rate approval from FERC have been granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates. However, FERC customarily reserves the right to suspend, upon complaint, market-based rate authority on a prospective basis if it is subsequently determined that we or any of our EWGs exercised market power. If FERC were to suspend market-based rate authority, it would most likely be necessary to file, and obtain FERC acceptance of, cost-based rate schedules for any of our EWGs. Also, the loss of market-based rate authority would subject the EWGs to the accounting, record-keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

In addition, if there occurs a "material change" in facts that might affect any of our subsidiaries' eligibility for EWG status, within 60 days of the material change, the relevant EWG must (1) file a written explanation of why the material change does not affect its EWG status, (2) file a new application for EWG status, or (3) notify FERC that it no longer wishes to maintain EWG status. If any of our subsidiaries were to lose EWG status, we, along with our affiliates, would be subject to regulation under PUHCA as a public utility company. Absent a substantial restructuring of our business, it would be difficult for us to comply with PUHCA without a material adverse effect on our business.

State Energy Regulation. In areas outside of wholesale rate regulation (such as financial or organizational regulation), some state utility laws may give their public utility commissions broad jurisdiction over steam sales or EWGs that sell power in their service territories. The actual scope of the jurisdiction over steam or independent power projects depends on state law and varies significantly from state to state.

Environmental Regulation

The construction and operation of power projects are subject to extensive environmental protection and land use regulation in the United States. These laws and regulations often require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies. If such laws and regulations are changed and our facilities are not grandfathered, extensive modifications to project technologies and facilities could be required.

General. Based on current trends, we expect that environmental and land use regulation will continue to be stringent. Accordingly, we actively review proposed construction projects that could subject us to stringent pollution controls imposed on "major modifications," as defined under the Clean Air Act, and changes in "discharge characteristics," as defined under the Clean Water Act. The goal of these actions is to achieve compliance with applicable regulations, administrative consent orders and variances from applicable air-quality related regulations.

Clean Air Act. Our Neil Simpson II and Wyodak plants located in Gillette, Wyoming are subject to Title IV of the Clean Air Act, which requires certain fossil-fuel-fired combustion devices to hold sulphur dioxide "allowances" for each ton of sulphur dioxide emitted. We currently hold sufficient allowances credited to us as a result of sulfur removal equipment previously installed at the Wyodak plant to apply to the operation of the Neil Simpson II plant and our interest in the Wyodak plant through 2030 without requiring the purchase of any additional allowances. With respect to any future plants, we plan to comply with the need for holding the appropriate number of allowances by reducing sulphur dioxide emissions through the use of low sulphur fuels, installation of "back end" control technology and the purchase of allowances on the open market. We expect to integrate the costs of obtaining the required number of allowances needed for future projects into our overall financial analysis of such projects.

Our plants are subject to a variety of regulations governing emissions of nitrogen oxides (NOx). On July 14, 2000, the South Coast Air Quality Management District (SCAQMD) sent a letter to our affiliate, Indeck Ontario, L.L.C (Indeck Ontario), the owner and operator of a 12 megawatt natural-gas fired cogeneration facility located in Ontario, California (Ontario Facility), stating that the SCAQMD had determined, as a result of a facility audit completed for the compliance year ended June 1, 1999, that the Ontario Facility's NOx emissions were 28,958 pounds over the Ontario Facility's NOx allocation established by the SCAQMD's RECLAIM emissions trading program. As a result, the SCAQMD indicated that it would be reducing the Ontario Facility's NOx allocation by the same number of allowances for the compliance year subsequent to a final determination on this issue. If a final determination is reached prior to June 30, 2001, the NOx allowances would be deducted from the Ontario Facility's allocation for the compliance year ended June 30, 2002. Indeck Ontario has provided documentation to the SCAQMD disputing this proposed reduction. In addition to this proposed reduction, which could affect the Ontario Facility's compliance with RECLAIM requirements for the 2001-2002 compliance period, Indeck Ontario also projects that its NOx emissions for the compliance year ended June 30, 2001 may be approximately 30,000 pounds over its current NOx allocation. There is currently significant volatility in the price and supply of RECLAIM NOx allowances; although the SCAQMD has proposed a revision to its regulations to stabilize the RECLAIM market, it is unclear whether such rules will minimize Indeck Ontario's potential exposure for its projected allowance shortfall. Accordingly, no assuance can be given at this time regarding whether RECLAIM NOx allowances will be available for purchase to allow Indeck Ontario to comply with RECLAIM requirements for the year ended June 30, 2001, or, if allowances are available, the cost of such allowances. Indeck Ontario may also be subject to administrative or civil penalties with respect to alleged violations of the SCAQMD's regulation for the compliance year ended June 30, 1999, although no notice of such penalties has been issued.

In July 1999, the United States Environmental Protection Agency (EPA) finalized rules designed to protect and improve visibility impairment resulting from air emissions. Among other things, the regulations required states to identify sources of emissions (including certain coal-fired generating units built between 1962 and 1977) by 2004 that would be subject to Best Available Retrofit Technology (BART). These sources would be required to implement BART within five years after the EPA approved state plans adopted to combat visibility impairment. The submission of these plans is due between 2004 and 2008. In January 2001, the EPA proposed guidance to assist states in determining which sources should be subject to the BART requirement, but the proposed guidance has not been published pending a review by the newly appointed Administrator of the EPA. Currently, the best available technology consists of "scrubbers," which are devices that trap pollutants in power-plant stacks. While we have installed scrubbers in our Wyodak and Neil Simpson II plants, we have not done so at the remainder of our coal-fired plants. If the proposed rules are adopted, management believes that the only existing plant which may be required to comply with Clean Air Act requirements is our Neil Simpson I plant and that any capital expenditures associated with bringing the plant into compliance would not have a material adverse effect on our financial condition or results of operations.

Title V of the Clean Air Act imposes federal requirements which dictate that all of our fossil fuel-fired generation facilities must obtain operating permits. All of our existing facilities subject to this requirement have submitted timely Title V permit applications and received permits.

On November 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act's "new source review" requirements related to modifications of air emissions sources at electric generating stations located in the southern and midwestern regions of the United States. Several states have joined these lawsuits. In addition, the EPA has also issued administrative notices of violation alleging similar violations at additional power plants owned by some of the same utilities named as defendants in the Department of Justice lawsuit, and also issued an administrative order to the Tennessee Valley Authority for similar violations at certain of its power plants. The EPA has also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities seeking to determine whether those utilities also engaged in activities that may have been in violation of the Clean Air Act's new source review requirements. To date, we are aware of three large utilities that have either settled with the United States or have reached agreements in principle to resolve such actions. In each case, the settling party has agreed (or agreed in principle) to incur over $1 billion in expenditures for the installation of additional pollution control, the retirement or repowering of coal-fired generating units, supplemental environmental projects and civil penalties. No such proceedings have been initiated or requests for information issued with respect to any of our facilities, but there can be no assurance that we will not be subject to such proceedings in the future.

In December 2000, the EPA announced its intention to regulate mercury emissions from coal-fired and oil-fired electric power plants under Section 112 of the Clean Air Act. The EPA is committed to proposing a rule to regulate such emissions by no later than 2003. Because we do not know what the EPA may require with respect to this issue, we are not able to evaluate the impact of potential mercury regulations on the operation of our facilities. Since the adoption of the United Nations Framework on Climate Change in 1992, there has been worldwide attention with respect to greenhouse gas emissions. In December 1997, the Clinton Administration participated in the Kyoto, Japan negotiations, where the basis of a Climate Change treaty was formulated. Under the treaty, known as the Kyoto Protocol, the United States would be required, by 2008-2012, to reduce its greenhouse gas emissions by 7 percent from 1990 levels. However, because of opposition to the treaty in the United States Senate, the Kyoto Protocol has not been submitted to the Senate for ratification. Although we are beginning to see legislative developments on the state level related to controlling greenhouse gas emissions, we are not aware of any such developments in the states in which we operate. If the United States ratifies the Kyoto Protocol or we otherwise become subject to limitations on emissions of carbon dioxide from our plants, such requirements could have a significant impact on our operations.

Clean Water Act. Our existing facilities are also subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges. Generally, such regulations are promulgated under authority of the Clean Water Act and govern overall water/wastewater discharges through National Pollutant Discharge Elimination System (NPDES) permits. Under current provisions of the Clean Water Act, existing NPDES permits must be renewed every five years, at which time permit limits are extensively reviewed and can be modified to account for changes in regulations or program initiatives. In addition, the permits have re-opener clauses which allow the permitting authority (which may be the United States or an authorized state) to attempt to modify a permit to conform to changes in applicable laws and regulations. Some of our existing facilities have been operating under NPDES permits for many years and have gone through one or more NPDES permit renewal cycles. Two of these facilities are currently in the process of renewing their existing NPDES permits.

Solid Waste Disposal. We dispose of all solid wastes collected as a result of burning coal at our power plants in approved solid waste disposal sites. Each disposal site has been permitted by the state of its location in compliance with law. Ash and wastes from flue gas and sulfur removal from the Wyodak and Neil Simpson II plants are deposited in mined areas. These disposal areas are located below some shallow water aquifers in the mine. None of the solid wastes from the burning of coal is classified as hazardous material, but the wastes do contain minute traces of metals that would be perceived as polluting if such metals were leached into underground water. Recent investigations have concluded that the wastes are relatively insoluble and will not measurably affect the post-mining ground water quality. Agreements in place require Pacific Power to be responsible for any such costs that would be related to the solid waste from its 80 percent interest in the Wyodak plant.

Additional unexpected material costs could also result in the future if the federal or state government determines that solid waste from the burning of coal contains some hazardous material that requires special treatment, including solid waste of which we previously disposed. In that event, the government regulator could consequently hold those entities that disposed of such waste responsible for such treatment.

Mine Reclamation. Under federal and state laws and regulations, we are required to submit to the regulation by, and receive approval from, the Wyoming Department of Environmental Quality (DEQ) for a mining and reclamation plan which provides for orderly mining, reclamation and restoration of all of our Wyodak cool mine in conformity with state laws and regulations. We have an approved mining permit and are otherwise in compliance with other land quality permitting programs.

One situation that could result in substantial unexpected increases in costs relating to our reclamation permit concerns three depressions -- the "south" depression, the "Peerless" depression and the "North Pit" depression - that have or will result from our mining activities at the Wyodak mine. Because of the thick coal seam and relatively shallow overburden, the current restoration plan would leave these depressions, which have limited reclamation potential, with interior drainage only. Although the DEQ has accepted the current plan to limit reclamation of these depressions, it has reserved the right to review and evaluate future reclamation plans or to reevaluate the existing reclamation plan. If as a result of our mining activities, additional overburden becomes available, the DEQ may require us to conduct additional reclamation of the depressions, particularly if the DEQ finds that the current limited reclamation is resulting in exceedances in the DEQ's water quality standards. Based on extensive reclamation studies, we have currently estimated the cost for reclamation for our mine at approximately $26 million and have currently accrued approximately $17.7 million on our balance sheet for these reclamation costs. No assurance can be given that additional requirements in the future may be imposed that would cause an unexpected material increase in reclamation costs.

Ben French Oil Spill. In 1990 and 1991, we discovered extensive underground fuel oil contamination at the Ben French plant site. With the help of expert consultants, we worked closely with the South Dakota Department of Environment and Natural Resources to assess and remediate the site. Our assessment and remediation efforts continue today and we continue to monitor the site. All of our underground oil-carrying facilities from which the contamination occurred are now above ground. There have been no significant recoveries of free fuel oil product since 1994. Soil borings and monitoring wells on the perimeters of our Ben French plant property provide no indication of contamination beyond the property's limits. Management believes that the underground spill has been sufficiently remedied so as to prevent any oil from migrating off site. However, due to underground gypsum deposits in this area, the fuel oil has the potential of migrating to area waterways. In such event, cleanup costs could be greatly increased. Management believes that sufficient remediation efforts to prevent such a migration are currently in place, but due to the uncertainties of underground geology, no assurance can be given.

Cleanup costs recognized to date total approximately $472,000, of which amount $386,000 has been reimbursed by the South Dakota Petroleum Release Compensation Fund. To date, no penalties, claims or actions have been taken or threatened against us because of this oil spill.

PCBs. Under the federal Toxic Substances Control Act, the EPA has issued regulations that control the use and disposal of polychlorinated biphenyls (PCBs). PCBs were widely used as insulating fluids in many electric utility transformers and capacitors manufactured before the Toxic Substances Control Act prohibited any further manufacture of PCB equipment. We remove and dispose of PCB-contaminated equipment in compliance with law as it is discovered.

Release of PCB-contaminated fluids, especially any involving a fire or a release into a waterway, could result in substantial cleanup costs. Several years ago, we began testing program of potential PCB-contaminated transformers, and in 1997 completed testing of all transformers and capacitors which are not located in our electric substations. We have not completed the testing of sealed potential transformers and bushings located in our electric substations as the testing of this equipment requires their destruction. Release of PCB-contaminated fluid, if present, from our equipment is unlikely and the volume of fluid in such equipment is generally less than one gallon. Moreover, any release of this fluid would be confined to our substation site.

Exploration and Production

Our oil and gas exploration and production operations are subject to various types of regulation at the federal, state and local levels. They include:

- requiring permits for the drilling of wells;
- maintaining bonding requirements in order to drill or operate wells;
- submitting and implementing spill prevention plans;
- submitting notification relating to the presence, use and release of certain contaminants incidental to oil and gas operations;
- regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in connection with drilling and production activities; and
- regulating surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production.

Our operations are also subject to various conservation matters, including the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in a unit and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratable purchase of production. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and to limit the number of wells or the locations at which we can drill. In addition, various federal, state and local laws and regulations concerning the discharge of contaminants into the environment, the generation, storage, transportation and disposal of contaminants and the protection of public health, natural resources, wildlife and environment affect our exploration, development and production operations and our related costs.

Other Properties

In addition to the other properties described herein, we own an eight-story office building consisting of approximately 47,000 square feet of office space in Rapid City, South Dakota. We occupy approximately 27,000 square feet in this building and lease the remainder to others.

Employees

At December 31, 2000, we had 635 employees, approximately 332 of whom are employed in our utility business, 170 of whom are employed in our independent energy businesses and 133 of whom are employed in our communications business.

Approximately one-half of our utility employees are covered by collective bargaining agreements with the International Brotherhood of Electrical Workers which expire on April 1, 2003. We have experienced no significant labor stoppages or labor disputes at our facilities.

ITEM 3. LEGAL PROCEEDINGS

PacifiCorp Litigation

In August 2000, we initiated an action in the United States District Court for the District of Wyoming against PacifiCorp relating to a coal supply agreement between PacifiCorp and us. We believe that PacifiCorp has failed to make complete payment to us for coal sold under the coal supply agreement and that PacifiCorp continues to underpay its monthly coal bill by approximately $100,000 per month. We believe that PacifiCorp's actions constitute a breach of the coal supply agreement and have asked for relief in the amount of $5,000,000, plus all underpayments since the commencement of our lawsuit.

PacifiCorp subsequently brought a counterclaim against us, alleging that we had not properly adjusted upward and downward the components which make up the coal price under the coal supply agreement, resulting in alleged overbilling to PacifiCorp of $35,000,000 to $40,000,000 over an undefined period. PacifiCorp further alleged that if past practices continue our adjustment methodology will result in additional overcharges of approximately $150,000,000 through the balance of the term of the coal supply agreement, which expires in June of 2013. In its action, PacifiCorp sought to cancel and terminate the contract and to recover monetary damages as proven at trial.

Management believes that we have properly billed PacifiCorp under the terms of the coal supply agreement and that PacifiCorp's withholding of payment constitutes a breach of contract on their part. Although it is impossible to predict whether we will ultimately be successful in defending PacifiCorp's claim or, if not successful, what the impact might be, management believes that disposition of this matter will not have a material adverse effect on our consolidated results of operations or financial condition. In addition, management believes that the pending litigation has not affected and will not affect our other agreements with PacifiCorp's subsidiary, Pacific Power.

Other Litigation

There are no other material legal proceedings pending, other than ordinary routine litigation incidental to our business, to which we are a party. There are no material legal proceedings to which an officer or director is a party or has a material interest adverse to us or our subsidiaries. There are no material administrative or judicial proceedings arising under environmental quality or civil rights statutes pending or known to be contemplated by governmental agencies to which we are or would be a party other than the SCAQMD RECLAIM requirements on the Ontario Facility "see ITEMS 1 AND 2. BUSINESS AND PROPERTIES - - Regulation - Environmental Regulation - Clean Air Act."

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

No matter was submitted to a vote of security holders during the fourth quarter of 2000.

PART II

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

Our common stock ($1 par value) is traded on The New York Stock Exchange. Quotations for the common stock are reported under the symbol BKH. At year-end, the Company had 5,708 common shareholders of record. All 50 states and the District of Columbia plus 10 foreign countries are represented.

We have declared common stock dividends payable in cash in each year since our predecessor's incorporation in 1941. At our January 2001 meeting, the Board of Directors raised the quarterly dividend to 28.0 cents per share, equivalent to an annual increase of 4.0 cents per share. This regular quarterly dividend is payable March 1, 2001. Dividend payment dates are normally March 1, June 1, September 1 and December 1.

Quarterly dividends paid and the high and low common stock prices for the last two years were as follows:

Year ended December 31, 2000

	1st	2nd	3rd	4th
Dividends paid per share	$0.27	$0.27	$0.27	$0.27
Common stock prices				
High	$25.19	$25.19	$30.13	$46.06
Low	$20.44	$20.88	$22.00	$27.00

Year ended December 31, 1999

	1st	2nd	3rd	4th
Dividends paid per share	$0.26	$0.26	$0.26	$0.26
Common stock prices				
High	$26.50	$23.88	$25.63	$23.31
Low	$21.00	$21.00	$22.19	$20.31

ITEM 6. SELECTED FINANCIAL DATA

Years ended December 31,	2000	1999	1998	1997	1996
TOTAL ASSETS (in thousands)	$1,320,320	$668,492	$559,417	$508,741	$467,354
PROPERTY AND INVESTMENTS (in thousands)					
Total property and investments	$1,136,094	$710,488	$619,549	$598,306	$581,537
Accumulated depreciation and depletion	277,848	246,299	229,942	197,179	181,103
Capital expenditures (includes AFUDC)	177,189*	154,609	27,225	28,319	24,388
CAPITALIZATION (in thousands)					
Long-term debt	$307,092	$160,700	$162,030	$163,360	$164,691
Preferred stock equity	4,000	-	-	-	-
Common stock equity	278,346	216,606	206,666	205,403	193,175
Total capitalization	$589,438	$377,306	$368,696	$368,763	$357,866
CAPITALIZATION RATIOS					
Long-term debt	52.1%	42.6%	43.9%	44.3%	46.0%
Preferred stock equity	0.7	-	-	-	-
Common stock equity	47.2	57.4	56.1	55.7	54.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%
AVERAGE INTEREST RATE ON LONG-TERM DEBT	8.2%	8.1%	8.1%	8.1%	8.1%
TOTAL OPERATING REVENUES	$1,623,836	$791,875	$679,254	$313,662	$162,588
NET INCOME AVAILABLE FOR COMMON STOCK (in thousands)	$52,770	$37,067	$25,808**	$32,359	$30,252
DIVIDENDS PAID ON COMMON STOCK (in thousands)	$23,527	$22,602	$21,737	$20,540	$19,930
COMMON STOCK DATA (in thousands)					
Shares outstanding, average	22,118	21,445	21,623	21,692	21,660
Shares outstanding, end of year	22,921	21,372	21,578	21,705	21,675
(in dollars)					
Basic earnings per average share	$ 2.39	$ 1.73	$ 1.19**	$ 1.49	$ 1.40
Diluted earnings per average share	$ 2.37	$ 1.73	$ 1.19**	$ 1.49	$ 1.40
Dividends paid per share	$ 1.08	$ 1.04	$ 1.00	$ 0.95	$ 0.92
Book value per share, end of year	$ 12.14	$ 10.14	$ 9.58	$ 9.46	$ 8.91
RETURN ON COMMON STOCK EQUITY (year-end)	19.0%	17.1%	12.5%*	15.8%	15.7%

*Excludes the non-cash acquisition of Indeck Capital, Inc.
**Includes impact of $8.8 million, or 41 cents per average share, write down of certain oil and gas properties

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

We are a growth oriented, diversified energy holding company operating principally in the United States. Our regulated and unregulated businesses have expanded significantly in recent years. Our independent energy group produces and markets fuel and power. We produce and sell electricity in a number of markets, with a strong emphasis in the western United States. We produce coal, natural gas and crude oil primarily in the Rocky Mountain region and market fuel products nationwide. We also own Black Hills Power, Inc., an electric utility serving 58,600 customers in South Dakota, Wyoming and Montana. Our communications group offers state-of-the-art broadband communications services to residential and business customers in Rapid City and the northern Black Hills region of South Dakota.

At our annual meeting of shareholders on June 20, 2000, our shareholders approved the formation of a holding company structure through a "plan of exchange" between Black Hills Corporation and Black Hills Holding Corporation. The plan of exchange provided that each share of Black Hills Corporation common stock would be exchanged for one share of common stock of the holding company. The formation of our holding company structure allows us to pursue, through separate subsidiaries, business opportunities in both regulated and unregulated markets.

On December 22, 2000, articles of exchange were filed with the South Dakota Secretary of State. As a result:

- all common shareholders of Black Hills Corporation became shareholders of Black Hills Holding Corporation, the holding company;

- Black Hills Corporation became a wholly-owned subsidiary of Black Hills Holding Corporation;

- Black Hills Corporation changed its name to "Black Hills Power, Inc." and the holding company changed its name to "Black Hills Corporation;" and

- Black Hills Power's debt securities and other financial obligations continue to be obligations of Black Hills Power.

Results of Operations

Consolidated Results

Consolidated net income for 2000 was $52.8 million compared to $37.1 million in 1999 and $25.8 million in 1998 or $2.37 per average common share in 2000, compared to $1.73 and $1.19 per average common share in 1999 and 1998, respectively. This equates to a 19.0 percent, 17.1 percent and 12.5 percent return on year-end common equity in 2000, 1999 and 1998, respectively.

We reported record earnings in 2000 primarily due to strong natural gas marketing activity, increased fuel production, expanded power generation and increased off-system electric utility wholesale sales. Strong results in our independent energy business group in 2000 were partially offset by start-up losses in our communications business. Unusual energy market conditions stemming primarily from gas and electricity shortages in California contributed to our strong financial performance in 2000.

Earnings per share for 2000 were approximately $0.40 higher due to prevailing prices of gas and electricity and extremely wide gas trading margins that may not recur in the future. Some of the energy markets in which we are active have recently experienced extreme volatility resulting from California's fuel and electricity shortages. Our fuel production, fuel marketing and power sales exposure in these markets is primarily indirect through sales to credit-worthy counterparties, including neighboring utilities and gas and power marketing firms.

Earnings in 1999 increased over 1998 due primarily to sales growth in our electric utility and improved results in our independent energy business group, partially offset by expected start-up losses in our communications business.

In 1998, we recorded an $8.8 million (net-of-tax) charge to earnings related to a write down of certain oil and natural gas properties. Absent this charge, our earnings per average common share for 1998 would have been $1.60, and our return on year-end common equity would have been 16.1 percent. The write down was primarily due to historically low crude oil prices, lower natural gas prices and a decline in value of certain unevaluated properties.

Consolidated revenues were $1.6 billion, $791.9 million and $679.3 million in 2000, 1999 and 1998, respectively, representing a 105 percent increase in 2000 and a 17 percent increase in 1999.

The dramatic growth in revenues in 2000 was a result of high energy commodity prices and increased volumes of fuel marketed, primarily as a result of extreme price volatility in the western markets, acquisitions and growth in the independent energy business group and increases in off-system sales by our electric utility. Natural gas prices increased from an average of $1.97-$2.15 per MMcf in 1998 and 1999 to $4.19 per MMcf in 2000. Daily volumes of natural gas marketed increased 36 percent from 635,500 MMBtus per day in 1999 to 860,800 MMBtus in 2000.

Revenue increases in 1999 resulted primarily from the acquisitions and growth in the fuel marketing segment of our independent energy business group and off-system sales by our electric utility.

Revenue and net income (loss) provided by each business group as a percentage of our total revenue and net income were as follows:

	2000	1999	1998
Revenue:			
Independent energy	89%	83%	81%
Electric utility	11	17	19
Communications	-	-	-
	100%	100%	100%
Net Income (Loss):			
Independent energy	55%	31%	5%
Electric utility	70	74	96
Communications	(25)	(5)	(1)
	100%	100%	100%

We believe that opportunities exist to continue the improvement of results from our existing operations in the independent energy business group. The independent energy group's earnings are expected to exceed net income derived from our regulated utility in 2001. Our coal mining and oil and gas segments of this business group have provided, and are expected to continue to provide, stable cash flow and operating results. We also believe our fuel marketing operations will continue to provide strong earnings and significant revenues and our continued expansion into the independent power generation business will have a positive impact on our independent energy business group in terms of future growth and earnings. (See Business Outlook Statements.)

Our electric utility has continued its stable growth both in terms of revenue and earnings over the past two years in our retail markets. We believe this trend is stable and, absent unplanned system outages, will continue for the next several years due to the extension of our electric utility's rate freeze until January 1, 2005. (See Rate Regulation.) The degree of the utility's future earnings generated from wholesale non-firm sales will depend on many factors including native load growth, plant availability and commodity prices in the western markets.

Although our communications business significantly increased residential and business customers in 2000, we expect it will sustain approximately $10 million in net losses in 2001, with annual losses decreasing and profitability expected in the next three to four years.

The following business group and segment information includes intercompany eliminations.

Independent Energy

	2000	1999	1998
		(in thousands)	
Revenue:			
Fuel marketing	$1,353,795	$614,228	$506,043
Coal	30,530	31,095	31,413
Gas and oil	19,183	13,052	12,562
Independent power	39,331	-	-
Total revenue	1,442,839	658,375	550,018
Expenses	1,381,991	644,196	536,048*
Operating income	$ 60,848	$ 14,179	$ 13,970*
Net income	$ 28,946	$ 11,882	$ 10,068*
EBITDA**	$ 65,184	$ 25,016	$ 22,530

- ---------------

* Excludes $13.5 million pre-tax non-cash charge relating to certain oil and gas assets ($8.8 million net-of-tax) **EBITDA represents the sum of earnings before interest, taxes, depreciation and amortization.

EBITDA is included because our management believes that EBITDA is a meaningful measurement commonly used by the investment community as an indicator of a company's historical ability to service debt, to sustain potential future increases in debt and to satisfy capital requirements. Our definition of EBITDA may not be identical to similarly titled measures reported by other companies. EBITDA is not intended to represent cash flows for the period, nor has it been presented as an alternative to either operating income or as an indicator of operating performance or cash flows from operating, investing and financing activities; is not intended to represent funds available for debt service, dividends, reinvestment, or other discretionary uses; and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with generally accepted accounting principles.

The following is a summary of coal, oil and gas production sales and marketing volumes:

	2000	1999	1998
Tons of coal sold	3,050,000	3,180,000	3,280,000
Barrels of oil sold	334,000	318,000	344,000
Mcf of natural gas sold	3,274,000	2,791,000	2,056,000
Mcf equivalent sales	5,278,000	4,698,000	4,120,000
Fuel marketing-average daily volumes:			
Natural gas - MMBtus	860,800	635,500	524,800
Crude oil - barrels	44,300	19,270	19,000
Coal - tons	4,400	4,500	4,400*

* Since the acquisition date

The independent energy business group's revenues increased 119 percent in 2000 and 20 percent in 1999. The revenue increase in 2000 was a direct result of gas and electricity shortages in the West Coast markets and the closing of the Indeck Capital, Inc. acquisition. The revenue increase in 1999 was primarily the result of consolidating the three fuel marketing companies' operations from the time of their acquisitions. Additionally, revenues increased in both years as a result of increased volumes and increased fuel and power prices. Natural gas prices increased from an average of $1.97-$2.15 per MMcf in 1998 and 1999 to $4.19 per MMcf in 2000. Daily volumes of natural gas marketed increased 35 percent in 2000 and 21 percent in 1999. In July 2000, we completed our acquisition of Indeck Capital, merging it into Black Hills Energy Capital, Inc., which contributed to our earnings growth in 2000. In addition, in December 2000, we sold our ownership interest in a power fund management company which resulted in a $3.7 million pre-tax gain.

The independent energy business group's total operating expenses, operating income and EBITDA increased over 115 percent, 325 percent and 160 percent, respectively, in 2000. Net income of the business group increased 144 percent in 2000. These increases resulted primarily from our gas marketing operations - which experienced a dramatic increase in both trading volumes and margins, a significant increase in fuel production volumes, record fuel and power prices and expanded power generation. The independent energy business group's 1999 net income improved over 1998 (excluding the non-cash charge in 1998) primarily due to record gas production, improved oil prices, lower depletion expense and the sale of certain retail gas marketing operations in 1999, partially offset by a non-cash write-down of certain intangible assets relating to our wholesale gas marketing office in Houston.

Coal Mining

Coal mining results were as follows:

	2000	1999	1998
		(in thousands)	
Revenue	$30,530	$31,095	$31,413
Operating income	8,800	12,600	12,700
Net income	7,200	9,700	9,750
EBITDA	19,000	15,700	15,600

A planned five-week outage at the Wyodak plant resulted in lower coal sales and earnings in 2000 compared to 1999 and 1998.

Oil and Gas

Oil and gas operating results were as follows:

	2000	1999	1998
		(in thousands)	
Revenue	$19,183	$13,052	$ 12,562
Operating income	7,900	4,000	1,200*
Net income	5,000	2,500	800*
EBITDA	11,900	6,900	6,400

*Excludes the impact of a $13.5 million pre-tax write-down of certain oil and natural gas properties.

Record net income in 2000 was primarily a result of record natural gas prices, higher crude oil prices, and a significant increase in production volumes. 1998 operating results were decreased primarily as a result of historically low crude oil prices, which not only reduced revenue but also increased depletion expense (lower oil and gas prices reduce the economically recoverable reserve amounts causing an increase in depletion expense). We recognized approximately $3.7 million, $2.6 million and $4.9 million of depletion expense (excluding the write-down in 1998) related to gas and oil production in 2000, 1999 and 1998, respectively.

The following is a summary of our oil and gas reserves at December 31:

	2000	1999	1998
Barrels of oil (in millions)	4.41	4.11	2.37
MMcf of natural gas	18.4	19.5	16.0
Total in MMcf equivalents	44.88	44.11	30.16

These reserves are based on reports prepared by Ralph E. Davis Associates, Inc., an independent consulting and engineering firm. Reserves were determined using constant product prices at the end of the respective years. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. The increase in oil reserves at December 31, 2000 was due to improved product prices. The increase in reserves at December 31, 1999 was due to strong drilling results, reserve acquisitions and improved product prices. We intend to increase our net proved reserves by selectively increasing our oil and gas exploration and development activities and by acquiring producing properties.

Fuel Marketing

Our fuel marketing companies produced the following results:

	2000	1999	1998
		(in thousands)	
Revenue	$1,353,795	$614,228	$506,043
Operating income (loss)	23,800	(2,200)	-
Net income	14,000	(200)	(300)
EBITDA	23,700	2,500	600

Record volumes marketed and strong margins contributed to the increase in net income from fuel marketing in 2000 compared to 1999 and 1998. During 1999, the fuel marketing companies sold certain of their retail gas marketing operations, resulting in after-tax gains of approximately $1.8 million. In 1999, revenue and the related cost of sales increased primarily due to a full year of coal marketing operations (acquired in September 1998), increased product prices and increased oil volumes marketed. Operating income in 1999 was reduced by a non-cash write-down of certain intangible assets relating to the wholesale gas marketing office in Houston in the amount of approximately $1.2 million (net-of-tax).

Our fuel marketing companies generate large amounts of revenue and corresponding expense related to buying and selling energy commodities. Fuel marketing is extremely competitive, and margins are typically very small. The unusual energy market conditions stemming primarily from natural gas and electricity shortages in California contributed to the strong financial performance in 2000 and may not recur in the future. However, we believe that the continued growth of our fuel and power production businesses will create opportunities for us to continue to generate strong fuel marketing operating results in future years.

Independent Power Production

Our independent power segment produced the following results:

	2000	1999	1998
		(in thousands)	
Revenue	$39,331	$ -	$ -
Operating income (loss)	20,400	(160)	-
Net income	3,200	(100)	(100)
EBITDA	10,751	-	(150)

Results from the independent power production segment were not significant either in 1999 or 1998. In July 2000, the acquisition of Indeck Capital was completed representing a significant advancement of our position in the independent power production segment. We now own 250 net megawatts in currently operating plants with a total name plate rating of approximately 870 megawatts. Of this 250 net megawatts, approximately 179 megawatts is under long-term contracts or tolling arrangements with at least one year remaining; approximately 40 megawatts is owned through minority interests in independent power investment funds, which we do not manage; and the remainder is sold under short-term market arrangements. An additional 470 megawatts of generating capacity is currently under construction. We expect to sell all of this output under long-term contracts. We expect to increase revenues and earnings in this segment beyond 2001 through future project development.

Electric Utility

	2000	1999	1998
		(in thousands)	
Revenue	$173,308	$133,222	$129,236
Operating expenses	105,100	80,936	79,340
Operating income	$ 68,208	$ 52,286	$ 49,896
Net income	$ 37,105	$ 27,286	$ 24,825
EBITDA	$ 88,853	$ 68,299	$ 64,936

Electric revenue increased 30.1 percent in 2000 compared to 3.1 percent in 1999. The increase in electric revenue in 2000 was primarily due to a 54 percent increase in off-system sales at an average price that was 3.1 times higher than the average price in 1999. The increase in off-system sales was driven by high spot market prices for energy in 2000, which enabled us to generate more energy from our combustion turbine facilities, including the Neil Simpson combustion turbine which we placed into commercial operation in June 2000. Megawatthours generated from our oil-fired diesel and natural gas-fired combustion turbines were 305,767 in 2000, 25,882 in 1999 and 33,082 in 1998. Historically, market prices were not sufficient to support the economics of generating from these facilities except to meet peak demand and as standby use for native load requirements.

Firm kilowatthour sales increased 2.8 percent in 2000 compared to a decrease of 0.1 percent in 1999. Residential and commercial sales increases of 6 percent and 3 percent, respectively, in 2000 were partially offset by a 2 percent decrease in industrial sales, primarily due to load reductions at Homestake Gold Mine. Degree days, a measure of weather trends, were 16 percent above 1999 and 1 percent above normal in 2000. Degree days in 1999 were 9 percent below 1998 and 13 percent below normal. The increase in electric revenue in 1999 was primarily due to stable firm sales combined with a 20 percent increase in off-system sales.

Revenue per kilowatthour sold was 6.4 cents compared to 5.4 cents in 1999 and 1998. The number of customers in the service area increased to 58,601 from 57,709 in 1999 and from 56,856 in 1998. The revenue per kilowatthour sold in 2000 reflects a 54 percent increase in wholesale non-firm sales to 684,378 megawatthours and robust wholesale power prices. The revenue per kilowatthour sold in 1999 reflects the 20 percent increase in wholesale non-firm sales to 445,712 megawatthours. The revenue per kilowatthour sold in 1998 reflects the 33 percent increase in wholesale non-firm sales to 371,104 megawatthours.

Electric utility operating expenses increased by 30 percent in 2000 primarily due to increased fuel, purchased power, and operating and maintenance expenses, partially offset by lower depreciation. Fuel expense in 2000 included the cost associated with the additional combustion turbine generation. Operating expenses increased 2.0 percent in 1999, primarily due to increased purchase power expense, operations and maintenance expenses and depreciation, partially offset by lower fuel expense.

Firm energy sales in our retail service territory are forecasted to increase over the next 10 years at an annual compound growth rate of approximately 1 percent, with the system demand forecasted to increase at a rate of 2 percent. We currently have a winter peak of 344 megawatts established in December 1998 and a summer peak of 372 megawatts established in August 2000. These forecasts are from studies conducted by us whereby our service territory is examined and analyzed to estimate changes in the needs for electrical energy and demand over a 20-year period. These forecasts are only estimates, and the actual changes in electric sales may be substantially different. However, in the past the forecasts have tracked actual sales within a band of reasonableness over a period of several years. Weather deviations can affect energy sales significantly when compared to forecasts based on normal weather.

Communications

	2000	1999	1998
		(in thousands)	
Revenue	$ 7,689	$ 278	$ -
Operating expenses	20,175	4,852	1,087
Operating loss	$(12,486)	$(4,574)	$(1,087)
Net loss	$(12,027)	$(1,262)	$ (280)
EBITDA	$(13,144)	$(2,626)	$ (570)

In September 1998, we formed our communications business to provide facilities-based communications services for Rapid City and the northern Black Hills of South Dakota. We have invested more than $100 million in state-of-the-art technology that offers local and long distance telephone service, expanded cable television service, Internet access, and high-speed data and video services. The build-out is approximately 70 percent complete and is expected to be completed in 2001. Further capital expenditures of approximately $31.3 million are expected over the next two years to complete the build-out of the fiber optic network and to acquire customer premise equipment for sale to customers.

We began serving customers in late 1999 and market our communications services to schools, hospitals, cities, economic development groups, and business and residential customers. Operating losses in 2000 were attributable to increased interest, depreciation and operating expenses. In 1999, the operating losses were primarily due to start-up organizational costs, increased depreciation expense and increased interest expense associated with the capital deployment. As of December 31, 2000, we had 8,368 residential customers and 646 business customers. We have a manageable backlog and expect to more than double the number of customers in 2001. Our goal is to attain 50 percent residential penetration while serving 35 percent of all broadband business customers within our service territory.

Liquidity and Capital Resources

In 2000, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common stock and to pay long-term debt maturities. We funded property additions primarily related to construction of additional electric generation facilities for our independent energy business group through a combination of operating cash flow, increased short-term debt and long-term non-recourse project financing. Investing and financing activities increased primarily as a result of the acquisition of Indeck Capital in July 2000 and construction of several generating facilities. Cash flows from operations increased $0.7 million, primarily due to increased net income and depreciation partially offset by increased working capital. We expect increased operating cash flows resulting from our investing activities to support the additional indebtedness.

As part of our acquisition of Indeck Capital, we assumed $40.3 million of additional debt, through an increase in borrowings on our short-term credit facilities. In addition, we issued 1.537 million shares of common stock and 4,000 shares of convertible preferred stock to the former Indeck Capital stockholders.

In 1999, we generated cash from operations sufficient to meet our operating needs, to pay dividends on common stock, to pay long-term debt maturities and to provide financing for our investment in independent power assets. Property additions were primarily financed through increased short-term debt and notes payable. Cash flows from operations increased $19 million primarily due to increased net income and decreased working capital. Cash flows from investing activities increased substantially, primarily related to the deployment of our fiber optic communications network and our investment in the construction of generating facilities. Cash flows from financing activities increased primarily due to increased short-term indebtedness to fund our investing activities.

In the past, we have relied upon internally generated funds, issuance of short and long-term debt and sales of common stock to finance our activities. We expect an appropriate mix of financing options will be used to finance future activities. We expect to finance our independent energy business group's purchase and construction of electric generating facilities, primarily with long-term, non-recourse project level debt. We expect that any project-level debt will contain significant restrictions on distributions of cash from the project to us.

Dividends paid on our common stock totaled $1.08 per share in 2000. This reflected increases approved by our Board of Directors from $1.04 per share in 1999 and $1.00 per share in 1998. All dividends were paid out of current earnings. Our three-year annual dividend growth rate was 4.4 percent and our payout ratio for 2000 was 45 percent. In January 2001, our Board of Directors increased the quarterly dividend 3.7 percent to 28 cents per share. If this dividend is maintained during 2001, it will be equivalent to $1.12 per share, an annual increase of 4 cents per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Capital Requirements

Our primary capital requirements for the three years ended December 31, 2000 were as follows:

	2000	1999	1998
		(in thousands)	
Property and investment additions:			
Independent energy	$130,787	$73,656	$12,040
Electric utility	25,257	31,911	11,451
Communications and other	58,922	49,042	1,774
Common stock dividends	23,527	22,602	21,737
Fuel marketing assets	-	-	1,960
Maturities/redemptions of long-term debt	1,330	1,330	1,331
	$239,823	$178,541	$50,293

Our capital additions for 2000 were $215 million. The major capital items for the year included the following: acquisition of the net assets of Indeck Capital; completion of construction of the 80 megawatt gas-fired generation units at the Arapahoe site in Denver, Colorado, which we placed in service in May 2000; completion of construction of the 40 megawatt gas-fired Valmont combustion turbine unit located in Boulder, Colorado, which we placed in service in May 2000; acquisitions of various interests in partnerships in which we previously held a minority interest; completion of construction of the 40 megawatt gas-fired Neil Simpson combustion turbine unit at our Wyodak site, which we placed in service in June 2000; and the construction of our communications fiber optic network.

Forecasted capital requirements for projected plant construction, other independent energy investments, regulated utility capital improvements and completion of the communications network are as follows:

	2001	2002	2003
		(in thousands)	
Independent energy	$ 287,200	$ 208,390	$ 195,540
Electric utility	18,340	18,160	16,450
Communications	25,390	5,920	3,290
	$ 330,930	$ 232,470	$ 215,280

Our independent energy business group's forecasted capital requirements include the following:

- Acquisition of a 240 megawatt Fountain Valley gas-fired turbine generation facility currently under construction, located near Colorado Springs, Colorado. Construction is expected to be completed in mid-2001, with an expected cost of approximately $175 million.

- Completion of construction of a 40 megawatt gas-fired combustion turbine at our Wyodak, Wyoming site (expected in mid-2001).

- Completion of construction of a 40 megawatt gas-turbine expansion at our Valmont, Colorado site (expected in mid-2001).

- Completion of construction of a 50 megawatt combined-cycle expansion at our Arapahoe, Colorado site (expected in mid-2002).

- Expansion of the Harbor Power plant in Wilmington, California with a 30 megawatt combined-cycle upgrade. This expansion is currently in development, with anticipated completion in the second quarter of 2001. We have a 32 percent financial interest in Harbor Power.

- Acquisition of operating and non-operating interests in 74 gas and oil wells from Stewart Petroleum Corporation of Denver, Colorado, which is expected to be completed in April 2001.

- Expected development of an additional 400 megawatts of generating capacity in years 2002-2003.

In addition to the above forecasted capital items we will lease the Wygen I plant, a 90 megawatt coal fired plant under construction at our Wyodak, Wyoming site. The Wygen I plant will run on low-sulfur coal fed by conveyor from our adjacent Wyodak coal mine. The plant will burn approximately 500,000 tons of coal per year using the latest available environmental control technology.

The Wygen I plant will be similar in design to our Neil Simpson II facility, which was completed in 1995 at the same site. We anticipate that the Wygen I plant would be operational by March of 2003. Because of the leasing arrangement, the $130 million expected total construction costs of the plant are not included in the above three year capital expenditure forecast.

Forecasted capital expenditures for our electric utility operations include new transmission and substation projects, re-build projects on existing transmission lines, distribution projects in response to customer requests for electric service, capital projects associated with our utility's existing generation plants, and other miscellaneous items. We do not expect additional generation capacity to be added to our regulated utility over the forecast period.

Our communications group's capital requirements forecast primarily consists of 2001 costs related to the completion of the initial fiber optic network build-out in Rapid City and the northern Black Hills of South Dakota. The build-out is expected to be completed by November 2001, with forecasted capital expenditures thereafter consisting of capital improvements to the then existing network infrastructure.

Lines of Credit

We have established lines of credit with various banks totaling $290 million at December 31, 2000 and $115 million at December 31, 1999, which were available to support bank borrowings or to provide for letters of credit. There were $211 million of borrowings and $20.6 million of letters of credit issued under these lines of credit at December 31, 2000, and $96.6 million of borrowings and no letters of credit issued at December 31, 1999. We had no compensating balance requirements associated with these lines of credit.
The lines of credit are subject to periodic review and renewal during the year by the banks.

In addition, Enserco Energy, Inc. has a $90 million uncommitted, discretionary line of credit to provide support for the purchase of natural gas. We provide no guarantee to the lender under this facility. At December 31, 2000 and 1999, there were outstanding letters of credit issued under the facility of $69.8 million and $19.9 million, respectively, with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc. has a $25 million uncommitted, discretionary credit facility. This line of credit provides credit support for the purchases of crude oil by Black Hills Energy Resources. We provide no guarantee to the lender under this facility. At December 31, 2000 and 1999, Black Hills Energy Resources had letters of credit outstanding of $8.5 million and $13.2 million, respectively, and no balance outstanding on its overdraft line.

Coal Reclamation Reserves

Under our mining permit, we are required to reclaim all land where we have mined coal reserves. The cost of reclaiming the land is accrued as the coal is mined. While the reclamation process takes place on a continual basis, much of the reclamation occurs over an extended period after we mine the area. Approximately $0.7 million is charged to operations as reclamation expense annually. As of December 31, 2000, accrued reclamation costs were approximately $17.7 million.

Long-term Debt/Credit Ratings

The long-term debt component of our capital structure at December 31, 2000 and 1999 was 52 percent and 43 percent, respectively. With expected growth within the independent energy business group, we anticipate our long-term debt ratio will increase to 55-60 percent in the next five years.

Our first mortgage bonds are rated A1 by Moody's Investors Service, Inc. and A+ by Standard & Poor's Ratings Services. These ratings reflect the respective agencies' opinions of the credit quality of our utility's first mortgage bonds.
.

Market Risk Disclosures

Price Risk Management

Our operations are exposed to market risk stemming from changes in commodity prices. These changes could cause fluctuations in our earnings and cash flows. In the normal course of business, we actively manage our exposure to these market risks by entering into various hedging transactions, which are authorized under our policies that place clear controls on these activities. Hedging transactions involve the use of a variety of derivative financial instruments.

We have adopted Risk Management Policies and Procedures, approved by the Board of Directors, and reviewed routinely by the Audit Committee of the Board of Directors. The Risk Management Policies and Procedures include, but are not limited to, risk tolerance levels relating to authorized derivative financial instruments, position limits, authorization of transactions and credit exposure.

Operating margins earned by wholesale gas and crude oil marketing are relatively insensitive to commodity price fluctuations since most of the purchase and sales contracts do not contain fixed-price provisions. Generally, prices contained in these contracts are tied to a current spot or index price and, therefore, adjust directionally with changes in overall market conditions. We generally attempt to balance our fixed-price physical and financial purchase and sales commitments in terms of contract volumes, and the timing of performance and delivery obligations. However, we may, at times, have a bias in the market, within established guidelines, resulting from the management of our portfolio. To the extent a net open position exists, fluctuating commodity market prices can impact our financial position or results of operations, either favorably or unfavorably. The net open positions are actively managed, and the impact of changing prices on our financial condition at a point in time is not necessarily indicative of the impact of price movements throughout the year.

Effective January 1, 1999, we adopted the provisions of Emerging Issues Task Force Issue No. 98-10, "Accounting for Energy Trading and Risk Management Activities" (EITF 98-10) pursuant to the implementation requirements stated therein. The resulting effect of adoption of the provisions of EITF 98-10 was to alter our comprehensive method of accounting for energy-related contracts, as defined in that statement.

We account for all energy trading activities at fair value as of the balance sheet date and recognize currently the net gains or losses resulting from the revaluation of these contracts to fair value in our results of operations. As a result, substantially all of the energy trading activities of our gas marketing, crude oil marketing and coal marketing operations are accounted for under fair value accounting methodology as prescribed in EITF 98-10.

Through our independent energy business group, we utilize financial instruments for our fuel marketing services. These financial instruments include fixed for float swap financial instruments, basis swap financial instruments, and costless collars traded in the over-the-counter financial markets.

The derivatives are not held for speculative purposes but rather serve to hedge our exposure related to commodity purchases or sales commitments. Under EITF 98-10, these transactions qualify as energy trading activities that must be accounted for at fair value. As such, realized and unrealized gains and losses are recorded as a component of income. Because we do not speculate with "open" positions, substantially all of our trading activities are back-to-back positions where a commitment to buy/(sell) a commodity is matched with a committed sale/(buy) or financial instrument. The quantities and maximum terms of derivative financial instruments held for trading purposes at December 31, 2000 and 1999 are as follows:

December 31, 2000	Volume Covered	Max. Term (Years)
(MMBtus)		
Natural gas basis swaps purchased	25,577,894	2
Natural gas basis swaps sold	26,059,621	2
Natural gas fixed for float swaps purchased	6,476,222	1
Natural gas fixed for float swaps sold	7,360,560	1
(Tons)		
Coal tons sold	988,000	1
Coal tons purchased	896,000	1

December 31, 1999	Volume Covered	Max. Term (Years)
(MMBtus)		
Natural gas futures contracts purchased	860,000	1
Natural gas basis swaps purchased	17,741,500	4
Natural gas basis swaps sold	18,390,517	4
Natural gas fixed for float swaps purchased	9,490,486	1
Natural gas fixed for float swaps sold	10,994,521	1
Natural gas collar transactions; puts purchased, calls sold	408,500	1
Natural gas collar transactions; calls purchased, puts sold	318,500	1

As required under EITF 98-10, energy trading activities were marked to fair value on December 31, 2000, and the gains and losses recognized in earnings. The entries for the accompanying consolidated balance sheets and income statement are as follows (in thousands):

Instrument	Asset	Liability	Gain (loss)
Natural gas basis swaps	$13,391	$23,963	$(10,572)
Natural gas fixed for float swaps	24,617	27,110	(2,493)
Natural gas physical	23,391	9,427	13,964
Coal transactions	5,370	4,460	910
Crude oil transactions	1,523	1,000	523
Totals	$68,292	$65,960	$ 2,332

There were no significant differences between the fair values of derivative assets and liabilities at December 31, 1999.

Non-trading Energy Activities

To reduce risk from fluctuations in the price of oil and natural gas, we enter into swaps and costless collar transactions. We use these transactions to hedge price risk from sales of our forecasted crude oil and natural gas production. For such transactions, we utilize hedge accounting.

At December 31, 2000, we had fixed-for-float swaps for 17,000 barrels per month for the year 2001 to hedge our crude oil price risk with a fair value of $34,000. We had fixed for float swaps for 10,000 barrels per month for the year 2002 to hedge our crude oil price risk with a fair value of $416,000. We also had costless collars (purchased puts-sold calls) for 10,000 barrels per month for 2001 with a fair value of $323,000. We hedged our forecasted 2001 natural gas production with fixed for float swaps. We had fixed for float swaps for 1,581,000 MMBtus with a fair value of $(3.4) million. These amounts are not reflected in our December 31, 2000 consolidated balance sheet, but will be recorded as part of the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," on January 1, 2001.

Financing Activities

To reduce risk from fluctuations in interest rates, we enter into interest rate swap transactions. We use these transactions to hedge interest rate risk for variable rate debt financing. For such transactions, we utilize hedge accounting. At December 31, 2000, we had interest rate swaps with a notional amount of $127.4 million, which have a maximum term of six years and a fair value of $(7.5) million.

Credit Risk

In addition to the risk associated with price movements, credit risk is also inherent in our risk management activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. While we have not experienced significant losses due to the credit risk associated with these arrangements, we have off-balance sheet risk to the extent that the counterparties to these transactions may fail to perform as required by the terms of each such contract.

Interest Rate Risk

Our exposure to market risk for changes in interest rates relates primarily to our short-term investments and long-term debt obligations. As stated in our policy, we are averse to principal loss and ensure the safety and preservation of our investments by limiting default risk, market risk and reinvestment risk.

We mitigate default risk on short-term investments by investing in high credit quality securities consisting primarily of tax-exempt federal, state and local agency obligations, by periodically monitoring the credit rating of any investment issuer or guarantor and by limiting the amount of exposure to any one issuer. Our portfolio includes only securities with active secondary or resale markets to ensure portfolio liquidity. All short-term investments mature, by policy, in two years or less. The effect of a 100 basis point (1 percent) increase in interest rates would not have a material effect to our results of operations or financial condition, due to the short-term duration of the investment portfolio.

At December 31, 2000, we had $162.2 million of outstanding floating rate debt of which $34.8 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate.

The table below presents principal (or notional) amounts and related weighted average interest rates by year of maturity for our short-term investments and long-term debt obligations, including current maturities (in thousands).

	2001	2002	2003	2004	2005	Thereafter	Total
Cash equivalents							
Fixed rate	$ 24,913	$ -	$ -	$ -	$ -	$ -	$ 24,913
Average interest rate	6.23%	-	-	-	-	-	6.23%
Long-term debt							
Fixed rate	$ 3,070	$ 18,065	$ 3,122	$ 2,017	$ 2,026	$ 130,602	$ 158,902
Average interest rate	9.30%	6.98%	9.31%	9.50%	9.52%	8.30%	8.22%
Variable rate	10,890	11,919	12,968	14,380	15,560	96,433	162,150
Average interest rate	8.20%	8.20%	8.19%	8.19%	8.19%	8.10%	8.14%
Total long term debt	13,960	29,984	16,090	16,397	17,586	227,035	321,052
Average interest rate	8.44%	7.46%	8.41%	8.35%	8.35%	8.22%	8.18%

Rate Regulation

Existing Rate Regulation

In June 1999, the South Dakota Public Utilities Commission approved a settlement between us and the commission staff, which extended a rate freeze in effect since 1995 until January 1, 2005.

The South Dakota settlement provides that, absent an extraordinary event, we may not file for any increase in our rates or invoke any fuel and purchased power adjustment tariff which would take effect during the freeze period. The specified extraordinary events are:

- new governmental impositions increasing annual costs for South Dakota customers of more than $2.0 million;

- simultaneous forced outages of both our Wyodak plant and Neil Simpson II plant projected to continue at least 60 days;

- forced outages occurring to either plant which continue for a period of three months and are projected to last at least nine months;

- an increase in the Consumer Price Index at a monthly rate for six months which would result in a 10 percent or higher annual inflation rate;

- the loss of a South Dakota customer or revenue from an existing South Dakota customer that would result in a loss of revenue of $2.0 million or more during any 12-month period;

- the cost of coal to our South Dakota customers increases and is projected to increase by more than $2.0 million over the cost for the most recent calendar year; and

- electric deregulation occurs as a result of either federal or state mandate, which allows any of our customers to choose its provider of electricity at any time during the freeze period.

During the freeze period, except as identified above, we are undertaking the risks of:

- machinery failure;

- load loss caused by either an economic downturn or changes in regulation;

- increased costs under power purchase contracts over which we have no control;

- government interferences; and

- acts of nature and other unexpected events that could cause material losses of income or increases in costs of doing business.

However, the settlement anticipates that we will retain, during that period of time, earnings realized from more efficient operations, sales from load growth, and off-system sales of power and energy.

Over the last three years we have initiated an effort to enter into new contracts with our largest industrial customers. The new contracts contain "meet or release" provisions which grant us a five-year right to continue to serve a customer at market rates in the event of deregulation. Additionally, through our new General Service Large Optional Combined Account Billing Tariff, we have allowed general service customers to aggregate their loads. This tariff also provides us with a five-year right to continue to serve those customers in the event of deregulation. Our "meet or release" contracts currently total more than 116 megawatts of large commercial and industrial load. These contracts provide us the assurance of a firm local market for our power resources, should deregulation occur. These industrial and large commercial customers, together with our wholesale power sale agreements with the City of Gillette and Montana Dakota Utilities, equal approximately 48 percent of our utility's firm load.

Regulatory Accounting

We follow SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and our financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating us. As a result of our regulatory activity, a 50-year depreciable life for the Neil Simpson II plant is used for financial reporting purposes. If we were not following SFAS 71, a 35 to 40 year life would probably be more appropriate which would increase depreciation expense by approximately $0.6 million per year. If rate recovery of generation-related costs becomes unlikely or uncertain, due to competition or regulatory action, these accounting standards may no longer apply to our generation operations. In the event we determine that we no longer meet the criteria for following SFAS 71, the accounting impact to us would be an extraordinary noncash charge to operations of an amount that could be material. Criteria that may give rise to the discontinuance of SFAS 71 include increasing competition that could restrict our ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. We periodically review these criteria to ensure that the continuing application of SFAS 71 is appropriate.

Business Outlook Statements

Business Strategy

Our strategy is to build long-term shareholder value by deploying our development, operating and marketing expertise in the competitive energy and telecommunications industries. We plan to operate a mix of regulated utility and unregulated independent energy and communications businesses, with emphasis on power generation, fuel production and fuel marketing.

Future Independent Energy Activities

Our independent energy group is expected to exceed net income derived from our regulated utility beginning in 2001. The following key elements are an integral part of our plan to achieve this objective:

- grow our independent power segment by developing and acquiring power projects primarily in the western United States, where demand is strong and expected to grow, and, in particular, by expanding the generating capacity of our existing sites through a strategy known as "brownfield development;"

- sell a large percentage of the production from our newly developed projects through long-term contracts in order to secure attractive returns;

- increase our reserves of natural gas and crude oil and expand our fuel production;

- manage the risks inherent in fuel marketing by maintaining strict position limits that minimize price risk exposure and by conducting business with a diversified group of counterparties of high credit quality;

- exploit our fuel cost advantages and our operating and marketing expertise to remain a low-cost power producer;

- build and maintain strong relationships with wholesale energy customers; and

- capitalize on our utility's established market presence, relationships and customer loyalty to expand our independent energy businesses.

Future Communications Activities

Our communications operations are expected to have operating losses for the next three to four years. The recovery of capital investment and future profitability are dependent primarily on our ability to attract new customers, including customers from incumbent providers such as Qwest Communications and Midcontinent Communications, the incumbent telephone and cable television providers. Although we do not anticipate being regulated in the local markets we are unable to predict future markets, future government impositions and future economic conditions that could affect the profitability of the communications and technology operations.

Recent Developments and Acquisitions

In March 2001, we signed a definitive agreement to acquire a 240 megawatt gas-fired turbine generation facility located near Colorado Springs, Colorado from Enron Corporation. The transaction is expected to close around March 31, 2001.

The Fountain Valley facility features six LM-6000 simple-cycle, gas-fired turbines, a technology identical to our existing facilities in Colorado and Wyoming. All necessary permitting has been approved and the plant is expected to phase in its generation capacity beginning in May 2001. We also announced that we obtained an 11-year contract with Public Service of Colorado to utilize the plant for peaking purposes. The contract is a tolling arrangement in which we assume no fuel costs. The cost of the project is expected to be approximately $175 million. We expect to finance the project primarily with non-recourse project level debt, and negotiations are presently under way with certain lenders.

Risks and Uncertainties

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (Reform Act), we are hereby filing cautionary statements identifying important factors that could cause our actual results to differ materially from those projected in forward-looking statements (as such term is defined in the Reform Act) made by or on behalf of the Company in our Annual Report on Form 10-K, Annual Report, Quarterly Report on Form 10-Q, and presentations, or in response to questions or otherwise. These statements concern our plans, expectations and objectives for future operations. All statements, other than statements of historical fact, that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. The words "anticipate," "believe," "estimate," "expect," "intend," "plan," "predicts," "project," "will likely result," "will continue," or similar expressions are not statements of historical fact and may be forward-looking. These forward-looking statements include, among others, such things as:

- expansion and growth of our business and operations;

- future financial performance;

- future acquisition and development of power plants;

- future production of coal, oil and natural gas;

- reserve estimates; and

- business strategy.

Forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from those contained in the forward-looking statements, including the following factors:

- prevailing governmental policies and regulatory actions, with respect to allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power and other capital investments, and present or prospective wholesale and resale competition;
- economic and geographic factors, including political and economic risk;
- changes in and compliance with environmental and safety laws and policies;
- weather conditions;
- population growth and demographic patterns;
- competition for retail and wholesale customers;
- pricing and transportation of commodities;
- market demand, including structural market changes;
- changes in tax rates or policies or in rates of inflation;
- changes in project costs;
- unanticipated changes in operating expenses or capital expenditures;
- capital market conditions;
- credit-worthiness of counterparties;
- technological advances;
- competition for new energy development opportunities; and
- legal and administrative proceedings that influence our business and profitability.

Any forward-looking statement speaks only as to the date on which that statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of an anticipated event. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders of Black Hills Corporation:

We have audited the accompanying consolidated balance sheets of Black Hills Corporation (a South Dakota corporation) and Subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, common stockholders' equity and cash flows for each of the three years in the period ended December 31, 2000. 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 auditing standards generally accepted in the United States. 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 Black Hills Corporation and Subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Minneapolis, Minnesota,
January 26, 2001

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2000	1999	1998
	(in thousands, except per share amounts)		
Operating revenues	$1,623,836	$ 791,875	$ 679,254
Operating expenses:			
Fuel and purchased power	1,370,841	637,302	531,518
Operations and maintenance	46,054	36,463	32,701
Administrative and general	44,423	18,272	15,747
Depreciation, depletion and amortization	32,864	25,067	24,037
Oil and gas ceilings test write down	-	-	13,546
Taxes, other than income taxes	14,904	12,880	12,472
	1,509,086	729,984	630,021
Operating income	114,750	61,891	49,233
Other income (expense):			
Interest expense	(30,342)	(15,460)	(14,707)
Interest income	7,075	3,614	2,861
Other, net	2,996	876	129
	(20,271)	(10,970)	(11,717)
Income before minority interest and income taxes	94,479	50,921	37,516
Minority interest	(11,273)	1,935	-
Income taxes	(30,358)	(15,789)	(11,708)
Net income	52,848	37,067	25,808
Preferred stock dividends	(78)	-	-
Net income available for common stock	$ 52,770	$ 37,067	$ 25,808
Earnings per share of common stock:			
Basic	$ 2.39	$ 1.73	$ 1.19
Diluted	$ 2.37	$ 1.73	$ 1.19
Weighted average common shares outstanding:			
Basic	22,118	21,445	21,623
Diluted	22,281	21,482	21,665

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

At December 31,	2000	1999
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24,913	$ 16,482
Securities available for sale	2,113	7,586
Receivables (net of allowance for doubtful accounts of $3,631 and $278, respectively) -		
Customers	278,436	84,331
Other	21,283	55,694
Materials, supplies and fuel	16,545	14,278
Prepaid expenses	7,428	2,828
Derivatives at market value	68,292	5,158
	419,010	186,357
Investments	63,965	10,444
Property and equipment	1,072,129	700,044
Less accumulated depreciation and depletion	(277,848)	(246,299)
	794,281	453,745
Other assets:		
Regulatory asset	4,134	3,944
Other, principally goodwill	38,930	14,002
	43,064	17,946
	$1,320,320	$668,492
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 13,960	$ 1,330
Notes payable	211,679	97,579
Accounts payable	247,596	80,355
Accrued liabilities	49,661	26,088
Derivatives at market value	65,960	5,158
	588,856	210,510
Long-term debt, net of current maturities	307,092	160,700
Deferred credits and other liabilities:		
Investment tax credits	2,530	3,022
Federal income taxes	62,679	47,668
Reclamation and regulatory liability	22,340	22,494
Other	16,516	7,492
	104,065	80,676
Minority interest in subsidiaries	37,961	-
Commitments and contingencies (Notes 10, 11 and 14)		
Stockholders' equity:		
Preferred stock - no par Series 2000-A; 21,500 shares authorized; Issued and outstanding: 4,000 shares in 2000, -0- shares in 1999	4,000	-
Common stock equity		
Common stock $1 par value; 100,000,000 shares authorized; Issued: 23,302,111 shares in 2000 and 21,739,030 shares in 1999	23,302	21,739
Additional paid-in capital	73,442	40,658
Retained earnings	191,482	162,239
Treasury stock	(9,067)	(8,030)
Accumulated other comprehensive income (loss)	(813)	-
	278,346	216,606
Total stockholders' equity	282,346	216,606
	$1,320,320	$ 668,492

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,	2000	1999	1998
		(in thousands)	
Operating activities:			
Net income available for common	$52,770	$37,067	$25,808
Principal non-cash items-			
Depreciation, depletion and amortization	32,864	25,067	24,037
Oil and gas ceilings test write-down	-	-	13,546
Derivative fair value adjustment	(2,332)	-	-
Gain on sales of assets	(3,736)	(2,541)	-
Deferred income taxes and investment tax credits	1,937	2,291	(2,535)
Minority interest	11,273	(1,935)	-
Change in operating assets and liabilities-			
Accounts receivable	(201,309)	2,232	(46,821)
Materials, supplies, fuel and other current assets	(3,513)	(4,003)	(2,954)
Accounts payable	165,394	6,268	41,465
Accrued liabilities	18,678	4,013	2,244
Other, net	2,444	5,284	(60)
	74,470	73,743	54,730
Investing activities:			
Property additions	(134,855)	(102,290)	(25,265)
Increase in investments	(13,646)	(52,319)	(1,960)
Payment for acquisition of net assets, net of cash acquired	(28,688)	-	-
Proceeds from sales of assets	5,500	3,463	-
Available for sale securities purchased	-	(7,870)	(22,361)
Available for sale securities sold	4,660	22,959	13,655
	(167,029)	(136,057)	(35,931)
Financing activities:			
Dividends paid	(23,527)	(22,602)	(21,737)
Treasury stock purchased	(1,037)	(4,949)	(3,081)
Common stock issued	3,854	424	273
Increase in short-term borrowings	73,848	92,489	5,067
Long-term debt - issuance	60,082	-	-
Long-term debt - repayments	(1,330)	(1,330)	(1,331)
Subsidiary distributions to minority interests	(10,900)	-	-
	100,990	64,032	(20,809)
Increase (decrease) in cash and cash equivalents	8,431	1,718	(2,010)
Cash and cash equivalents:			
Beginning of year	16,482	14,764	16,774
End of year	$ 24,913	$ 16,482	$ 14,764
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest	$31,309	$18,819	$14,742
Income taxes	$18,518	$13,173	$13,135
Non-cash net assets acquired through issuance of common and preferred stock (Note 14)	$34,493	$ -	$ -

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Common Stock		Additional		Treasury Stock		Accumulated Other	
	Shares	Amount	Paid-In Capital	Retained Earnings	Shares	Amount	Comprehensive Income (loss)	Total
					(in thousands)			
Balance at December 31, 1997	21,705	$ 21,705	$ 39,995	$ 143,703	-	$ -	$ -	$205,403
Comprehensive Income:								
Net income	-	-	-	25,808	-	-	-	25,808
	-	-	-	25,808	-	-	-	25,808
Dividends on common stock	-	-	-	(21,737)	-	-	-	(21,737)
Issuance of common stock	14	14	259	-	-	-	-	273
Treasury stock acquired, net	-	-	-	-	(141)	(3,081)	-	(3,081)
Balance at December 31, 1998	21,719	21,719	40,254	147,774	(141)	(3,081)	-	$206,666
Comprehensive Income:								
Net income	-	-	-	-	37,067	-	-	37,067
	-	-	-	-	37,067	-	-	37,067
Dividends on common stock	-	-	-	(22,602)	-	-	-	(22,602)
Issuance of common stock	20	20	404	-	-	-	-	424
Treasury stock acquired, net	-	-	-	-	(227)	(4,949)	-	(4,949)
Balance at December 31, 1999	21,739	21,739	40,658	162,239	(368)	(8,030)	-	$216,606
Comprehensive Income:								
Net income	-	-	-	52,848	-	-	-	52,848
Unrealized loss on available for sale securities	-	-	-	-	-	-	(813)	(813)
	-	-	-	52,848	-	-	(813)	52,848
Dividends on preferred stock	-	-	-	(78)	-	-	-	(78)
Dividends on common stock	-	-	-	(23,527)	-	-	-	(23,527)
Issuance of common stock	26	26	544	-	-	-	-	570
Issuance of common stock for acquisition	1,537	1,537	32,240	-	-	-	-	33,777
Treasury stock acquired, net	-	-	-	-	(13)	(1,037)	-	(1,037)
Balance at December 31, 2000	23,302	$ 23,302	$ 73,442	$ 191,482	(381)	$(9,067)	$ (813)	$278,346

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2000, 1999 and 1998

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation and its subsidiaries operate in three primary operating groups: non-regulated independent energy, regulated electric utility and communications. The Company operates its independent energy businesses through its direct and indirect subsidiaries: Wyodak Resources related to coal, Black Hills Exploration and Production related to oil and natural gas, Enserco Energy, Black Hills Energy Resources and Black Hills Coal Network related to fuel marketing of natural gas, oil and coal, respectively, and Black Hills Energy Capital and its subsidiaries and Black Hills Generation related to independent power activities, all consolidated for reporting purposes as Black Hills Energy Ventures; operates its public utility electric operations through its subsidiary, Black Hills Power, Inc.; and operates its communications operations through its indirect subsidiaries Black Hills Fiber Systems, Black Hills FiberCom and Daksoft. For further descriptions of the Company's business segments see Note 13.

In December 2000, the Company effected a holding company structure under the renamed holding company Black Hills Corporation.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned subsidiaries. Generally, the Company uses equity accounting for investments of which it owns between 20 and 50 percent and investments in partnerships under 20 percent if the Company exercises significant influence.

All significant intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with intercompany coal sales in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." Total intercompany coal sales not eliminated were $9.7 million, $7.7 million and $10.3 million in 2000, 1999 and 1998, respectively.

The Company owns 51 percent of the voting securities of Black Hills FiberCom, LLC (FiberCom). During 2000 FiberCom's operating losses reduced its members' equity below zero. At that point the Company began to recognize 100 percent of FiberCom's operating losses and will continue to do so until such time as additional equity investments are made by third parties or future net income restores members' equity to a positive amount.

As noted in Note 14, Black Hills Energy Capital made several acquisitions during 2000. The Company's consolidated statements of income include operating activity of these companies beginning with their acquisition date.

The Company uses the proportionate consolidation method to account for its working interests in oil and gas properties.

Minority Interest in Subsidiaries

Minority interest in results of operations of consolidated subsidiaries represents the minority shareholders' share of the income or loss of various consolidated subsidiaries. The minority interest in the consolidated balance sheets reflect the amount of the underlying net assets of various consolidated subsidiaries attributable to the minority shareholders.

Regulatory Accounting

Black Hills Power is subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's non-regulated businesses.

Black Hills Power follows the provisions of SFAS No. 71, and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating Black Hills Power. As a result of Black Hills Power's 1995 rate case settlement, a 50-year depreciable life for Neil Simpson II is used for financial reporting purposes. If Black Hills Power were not following SFAS 71, a 35 to 40 year life would be more appropriate, which would increase depreciation expense by approximately $0.6 million per year. If rate recovery of generation-related costs becomes unlikely or uncertain, due to competition or regulatory action, these accounting standards may no longer apply to Black Hills Power's generation operations. In the event Black Hills Power determines that it no longer meets the criteria for following SFAS 71, the accounting impact to the Company would be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict Black Hills Power's ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure the continuing application of SFAS 71 is appropriate.

Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Available for Sale Securities

The Company has investments in marketable securities that are classified as available-for-sale securities and are carried at fair value in accordance with the provisions of SFAS No. 115 "Accounting for Certain Investments in Debt and Equity Securities." The unrealized gain or loss resulting from the difference between the securities' fair value and cost basis is included as a component of accumulated other comprehensive income in common stockholders' equity.

Inventory

Materials, supplies and fuel are stated at the lower of cost or market on a first-in, first-out basis.

Property, Plant and Equipment

The components of property, plant and equipment are as follows, at December 31:

	2000	1999
	(in thousands)	
Independent energy	$ 430,979	$125,371
Electric utility	530,529	523,461
Communications	110,486	50,621
Other	135	591
	$1,072,129	$700,044

Additions to property, plant and equipment are recorded at cost when placed in service. Included in the cost of regulated construction projects is an allowance for funds used during construction (AFUDC) which represents the approximate composite cost of borrowed funds and a return on capital used to finance the project. The AFUDC was computed at an annual composite rate of 9.7, 8.3 and 10.1 percent during 2000, 1999 and 1998, respectively. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $2.0 million, $1.2 million and $0.2 million in 2000, 1999 and 1998, respectively. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, together with removal cost less salvage, is charged to accumulated depreciation. Retirement or disposal of all other assets, except for oil and gas properties as described below, result in gains or losses recognized as a component of income. Repairs and maintenance of property are charged to operations as incurred.

Depreciation provisions for regulated electric property, plant and equipment is computed on a straight-line basis using an annual composite rate of 2.8 percent in 2000, 3.1 percent in 1999 and 3.0 percent in 1998. Non-regulated property, plant and equipment is depreciated on a straight-line basis using estimated useful lives ranging from 3 to 39 years. Depletion of coal, oil and gas properties is computed using the cost method.

The Company periodically evaluates assets under SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to Be Disposed Of," which requires that such assets be probable of future recovery at each balance sheet date. As of December 31, 2000 and 1999, no significant write-downs were required.

Goodwill and Intangible Assets

Goodwill represents the excess of acquisition costs over the fair market value of the net assets of acquired businesses and is being amortized on a straight-line basis over the estimated useful lives of such assets, which range from 8 to 25 years. The cost of other acquired intangibles is amortized on a straight-line basis over their estimated useful lives. Amortization expense was $3.1 million, $2.7 million and $0.7 million in 2000, 1999 and 1998, respectively. Accumulated amortization was $6.7 million, $3.6 million and $0.9 million at December 31, 2000, 1999 and 1998, respectively.

Income Taxes

The Company uses the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. To the extent such income taxes are recoverable or payable through future rates, regulatory assets and liabilities have been recorded in the accompanying consolidated balance sheets.

Deferred taxes are provided on all significant temporary differences, principally depreciation and depletion. Investment tax credits have been deferred in the electric operation and the accumulated balance is amortized as a reduction of income tax expense over the useful lives of the related electric property which gave rise to the credits.

Revenue Recognition

Generally, revenue is recognized at the time products and services are delivered. Fuel marketing businesses also use the mark-to-market method of accounting. Under that method all energy trading activities are recorded at fair value as of the balance sheet date and net gains or losses resulting from the revaluation of these contracts to fair value are recognized currently in the results of operations. In the fourth quarter of 2000, the Company adopted Securities and Exchange Commission Staff Accounting Bulletin No. 101, "Revenue

Recognition" (SAB 101), which provides guidance on the recognition, presentation and disclosure of revenue in financial statements. The adoption of SAB 101 did not have a material impact on the financial statements.

Oil and Gas Operations

The Company accounts for its oil and gas activities under the full cost method. Under the full cost method, all productive and nonproductive costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Under the full cost method, net capitalized costs may not exceed the present value of proved reserves.

Earnings Per Share of Common Stock

Basic earnings per share is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed under the treasury stock method and is calculated to compute the dilutive effect of outstanding stock options and conversion of preferred shares.

Use of Estimates

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

Reclassifications

Certain 1999 and 1998 amounts in the financial statements have been reclassified to conform to the 2000 presentation. These reclassifications had no effect on the Company's common stockholders' investment or results of operations, as previously reported.

Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities." SFAS 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

SFAS 133 allows special hedge accounting for fair value and cash flow hedges. The Statement provides that the gain or loss on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk be recognized currently in earnings in the same accounting period. SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings.

SFAS 133 requires that on date of initial adoption, an entity shall recognize all freestanding derivative instruments in the balance sheet as either assets or liabilities and measure them at fair value. The difference between a derivative's previous carrying amount and its fair value shall be reported as a transition adjustment. The transition adjustment resulting from adopting this Statement shall be reported in net income or other comprehensive income, as appropriate, as the effect of a change in accounting principle in accordance with paragraph 20 of Accounting Principles Board Opinion No. 20 (APB), "Accounting Changes."

Upon adoption of SFAS 133, most of the Company's energy trading activities previously accounted for under Emerging Issues Task Force Issue No. 98-10, "Accounting for Energy Trading and Risk Management Activities" (EITF 98-10) will fall under the purview of SFAS 133. The effect from this adoption on the energy trading companies and energy trading activities will not be material because, unless otherwise noted, the trading companies will not designate their energy trading activities as hedge instruments. This "no hedge" designation will result in these derivatives being measured at fair value and gains and losses recognized currently in earnings. This treatment under SFAS 133 will be comparable to the accounting under EITF 98-10.

At December 31, 2000, the Company had certain non-trading energy contracts documented as cash flow hedges. These contracts are defined as derivatives under SFAS 133 and meet the requirements for cash flow hedges. Because these non-trading energy contracts were documented as hedges prior to adoption, the transition adjustment will be reported in accumulated other comprehensive income. The aggregated entry for the derivatives identified as energy cash flow hedges will increase derivative assets by $1.4 million, increase the derivative liabilities by $4.0 million and decrease accumulated other comprehensive income by $2.6 million.

At December 31, 2000, the Company had interest rate swaps documented as cash flow hedges. These contracts are defined as derivatives under SFAS 133 and meet the requirements for cash flow hedges. Because these contracts were documented as hedges prior to adoption, the transition adjustment will be reported in accumulated other comprehensive income. The interest rate swap transactions have a notional amount of $127.4 million and the associated transition adjustments will increase derivative liabilities by $7.5 million and decrease accumulated other comprehensive income by $7.5 million.

(2) PRICE RISK MANAGEMENT

The Company is exposed to market risk stemming from changes in commodity prices. These changes could cause fluctuations in the Company's earnings and cash flows. In the normal course of business, the Company actively manages its exposure to these market risks by entering into various hedging transactions, which are authorized under its policies that place clear controls on these activities. Hedging transactions involve the use of a variety of derivative financial instruments.

Effective January 1, 1999, the Company adopted the provisions of EITF 98-10, pursuant to the implementation requirements stated therein. The resulting effect of adoption of the provisions of EITF 98-10 was to alter the Company's comprehensive method of accounting for energy-related contracts, as defined in that Statement.

The Company accounts for all energy trading activities at fair value as of the balance sheet date and recognizes currently the net gains or losses resulting from the revaluation of these contracts to fair value in its results of operations. As a result, substantially all of the energy trading activities of the Company's gas marketing, crude oil marketing, and coal marketing operations are accounted for under fair value accounting methodology as prescribed in EITF 98-10.

The Company, through its independent energy business group, utilizes financial instruments for its fuel marketing services. These financial instruments include fixed for float swap financial instruments, basis swap financial instruments and costless collars traded in the over-the-counter financial markets.

These derivatives are not held for speculative purposes but rather serve to hedge the Company's exposure related to commodity purchases or sales commitments. Under EITF 98-10, these transactions qualify as energy trading activities that must be accounted for at fair value. As such, realized and unrealized gains and losses are recorded as a component of income. Because the Company does not as a policy permit speculation with "open" positions, substantially all of its trading activities are back-to-back positions where a commitment to buy/(sell) a commodity is matched with a committed sale/(buy) or financial instrument. The quantities and maximum terms of derivative financial instruments held for trading purposes at December 31, 2000 and 1999 are as follows:

December 31, 2000	Volume Covered	Max. Term (Years)
(MMBtus)		
Natural gas basis swaps purchased	25,577,894	2
Natural gas basis swaps sold	26,059,621	2
Natural gas fixed for float swaps purchased	6,476,222	1
Natural gas fixed for float swaps sold	7,360,560	1
(Tons)		
Coal tons sold	988,000	1
Coal tons purchased	896,000	1

December 31, 1999	Volume Covered	Max. Term (Years)
(MMBtus)		
Natural gas futures contracts purchased	860,000	1
Natural gas basis swaps purchased	17,741,500	4
Natural gas basis swaps sold	18,390,517	4
Natural gas fixed for float swaps purchased	9,490,486	1
Natural gas fixed for float swaps sold	10,994,521	1
Natural gas collar transactions; puts purchased, calls sold	408,500	1
Natural gas collar transactions; calls purchased, puts sold	318,500	1

As required under EITF 98-10, energy trading activities were marked to fair value on December 31, 2000, and the gains and losses recognized in earnings. The entries for the accompanying consolidated balance sheet and income statement are as follows (in thousands):

Instrument	Asset	Liability	Gain (loss)
Natural gas basis swaps	$13,391	$23,963	$(10,572)
Natural gas fixed-for-float swaps	24,617	27,110	(2,493)
Natural gas physical	23,391	9,427	13,964
Coal transactions	5,370	4,460	910
Crude oil transactions	1,523	1,000	523
Totals	$68,292	$65,960	$ 2,332

There were no significant differences between the fair values of derivative assets and liabilities at December 31, 1999.

Non-trading Energy Activities

To reduce risk from fluctuations in the price of oil and natural gas, the Company enters into swaps and costless collar transactions. The transactions are used to hedge price risk from sales of the Company's forecasted crude oil and natural gas production. For such transactions, the Company utilizes hedge accounting.

At December 31, 2000, the Company had fixed-for-float swaps for 17,000 barrels per month for the year 2001 to hedge its crude oil price risk with a fair value that approximates cost. The Company had fixed-for-float swaps for 10,000 barrels per month for the year 2002 to hedge its crude oil price risk with a fair value of $0.4 million. The Company also had costless collars (purchased puts sold calls) for 10,000 barrels per month for 2001 with a fair value of $0.3 million. The Company hedged its forecasted 2001 natural gas production with fixed-for-float swaps. The Company had fixed-for-float swaps for 1,581,000 MMBtus with a fair value of $(3.4) million. These amounts are not reflected in the Company's December 31, 2000 consolidated balance sheet, but will be recorded as part of the adoption of SFAS 133 on January 1, 2001.

Financing Activities

To reduce risk from fluctuations in interest rates, the Company enters into interest rate swap transactions. These transactions are used to hedge interest rate risk for variable rate debt financing. For such transactions, the Company utilizes hedge accounting. At December 31, 2000, the Company had interest rate swaps with a notional amount of $127.4 million, having a maximum term of six years and a fair value of $(7.5) million.

At December 31, 2000, the Company had $162.2 million of outstanding, floating-rate debt of which $34.8 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate.

Credit Risk

In addition to the risk associated with price movements, credit risk is also inherent in the Company's risk management activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. While the Company has not experienced significant losses due to the credit risk associated with these arrangements, the Company has off-balance sheet risk to the extent that the counterparties to these transactions may fail to perform as required by the terms of each such contract.

(3) INVESTMENTS IN ASSOCIATED COMPANIES

Included in Investments on the Consolidated Balance Sheets are the following investments that have been recorded on the equity method of accounting:

- A 33.33 percent interest in Millennium Pipeline Company, L.P., a Texas limited partnership which owns and operates an oil pipeline in the Gulf Coast region of Texas. The Company has a carrying amount in the investment of $6.9 million and $4.8 million as of December 31, 2000 and 1999, respectively. The partnership had assets of $22.0 million and $15.7 million, liabilities of $1.0 million and $1.6 million, and net income (loss) of $2.8 million and $(0.2) million as of, and for the years ended December 31, 2000 and 1999, respectively.

- As part of the Indeck Capital, Inc. acquisition, the Company acquired a 5 percent, 6 percent and 5 percent interest in Energy Investors Fund, L.P., Energy Investors Fund II, L.P., and Project Finance Fund III, L.P., respectively, which in turn have investments in numerous electric generating facilities in the United States and elsewhere. The Company has a carrying amount in the investment of $8.4 million at December 31, 2000. As of, and for the year ended December 31, 2000, the funds had assets of $186.8 million, liabilities of $16.0 million and net income of $27.1 million.

- As part of the Indeck Capital acquisition, the Company acquired a 50 percent interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. At December 31, 2000 the Company's carrying amount in the investment is $4.1 million which includes $0.5 million that represents the cost of the investment over the value of the underlying net assets of the projects. This excess is being amortized over 19 years. As of, and for the year ended December 31, 2000, these projects had assets of $26.0 million, liabilities of $18.7 million and net income of $0.9 million.

- As part of the Indeck Capital acquisition, the Company directly and indirectly acquired approximately 32 percent of Harbor Cogeneration Company, which in turn owns an 80 megawatt cogeneration facility located near the City of Long Beach in Los Angeles County, California. At December 31, 2000 the Company's carrying amount in the investment is $42.2 million, which includes $13.7 million that represents the cost of the investment over the value of the underlying net assets of Harbor. This excess is being amortized over 15 years. As of, and for the year ended December 31, 2000, Harbor had assets of $41.7 million, liabilities of $0.8 million and net income of $28.8 million.

(4) COMMON STOCK

Stock Option and Employee Stock Purchase Plans

The Company has a stock option plan (Stock Option Plan), which allows for the granting of stock options with exercise prices equal to the stock's market value on the date of grant, and an employee stock purchase plan (ESPP Plan). The Company accounts for such plans under APB No. 25, and has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock Based Compensation" (SFAS No. 123). Accordingly, no compensation cost has been recognized.

The Company may grant options for up to 1,000,000 shares of common stock under the Stock Option Plan. The Company has granted options on 934,450 shares through December 31, 2000. The option exercise price equals the fair market value of the stock on the day of the grant. The options granted vest one-third a year for three years and all expire after ten years from the grant date.

A summary of the status of the stock option plans at December 31, 2000, 1999 and 1998, and changes during the years then ended are as follows:

	2000		1999		1998	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	431,450	$21.35	292,700	$20.29	182,700	$18.69
Granted	492,500	25.22	140,250	23.58	113,000	22.79
Forfeited	(4,000)	23.25	(1,500)	23.06	-	
Exercised	(5,033)	21.33	-		(3,000)	16.67
Balance at end of year	914,917	23.43	431,450	21.35	292,700	20.29
Exercisable at end of year	292,891	20.43	182,400	19.19	84,800	18.06

Exercise prices on options outstanding at December 31, 2000, range from $16.67 to $37.69 with a weighted average remaining contractual life of approximately 8.5 years.

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options are as follows:

	2000	1999	1998
Fair value of options at grant date	$3.88	$4.16	$0.69
Weighted average risk-free interest rate	6.30%	6.68%	4.70%
Weighted average expected price volatility	20.60%	19.85%	16.74%
Weighted average expected dividend yield	4.20%	4.50%	4.20%
Expected life in years	10	10	10

Had compensation cost been determined consistent with SFAS No. 123, the Company's net income and earnings per share would have been reduced to the following pro forma amounts for the years ended December 31:

	2000	1999	1998
	(in thousands, except per share amounts)		
Net income available for common:			
As reported	$52,770	$37,067	$25,808
Pro forma	$52,432	$36,877	$25,717
Earnings per share (basic and diluted):			
As reported - basic	$ 2.39	$1.73	$1.19
- diluted	$ 2.37	$1.73	$1.19
Pro forma - basic	$ 2.38	$1.72	$1.19
- diluted	$ 2.35	$1.72	$1.19

The Company issued 21,394, 19,565 and 12,824 shares of common stock under the ESPP Plan in 2000, 1999 and 1998, respectively. At December 31, 2000, 226,176 shares are reserved and available for issuance under the ESPP Plan. The Company sells the shares to employees at 90 percent of the stock's market price on the offering date. The fair value per share of shares sold in 2000 was $21.66.

Dividend Reinvestment and Stock Purchase Plan

The Company has a Dividend Reinvestment and Stock Purchase Plan under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100 percent of the recent average market price. The Company has the option of issuing new shares or purchasing the shares on the open market. The Company purchased shares on the open market in 2000, 1999 and 1998. At December 31, 2000, 1,290,797 shares of unissued common stock were available for future offerings under the Plan.

(5) PREFERRED STOCK

The Company has 25,000,000 authorized shares of no-par preferred stock.

During 2000, the Company issued 4,000 preferred shares in the Indeck Capital acquisition. The preferred shares issued are non-voting, cumulative, no par shares with a dividend rate equal to 1 percent per annum per share, computed on the basis of $1,000 per share plus an amount equal to any dividend declared payable with respect to the common stock, multiplied by the number of shares of common stock into which each share of preferred stock is convertible. The record and payment dates are the same as the record and payment dates with respect to the payment of dividends on common stock. No dividend may be declared or paid with respect to common stock unless such a dividend is declared and paid with respect to the preferred stock. The preferred stock is senior to the common stock in liquidation events.

The Company may redeem the preferred stock in whole or in part, at any time solely at its option. The redemption price per share for the preferred stock shall be $1,000 per share plus all accrued and unpaid dividends. Each share of the preferred stock is convertible at the option of the holder into common stock at any time prior to July 7, 2005 and automatically converted into common stock on July 7, 2005. Each share of preferred stock is convertible into 28.57 common shares. If the Company delivers a notice of redemption, the conversion price shall be adjusted to equal the lesser of (i) the conversion price then in effect, and (ii) the current market price on the redemption notice date.

(6) LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows (in thousands):

	2000	1999
First mortgage bonds:		
6.50% due 2002	$ 15,000	$ 15,000
9.00% due 2003	3,215	4,255
8.06% due 2010	30,000	30,000
9.49% due 2018	5,130	5,420
9.35% due 2021	35,000	35,000
8.30% due 2024	45,000	45,000
	133,345	134,675
Other long-term debt:		
Pollution control revenue bonds at 6.7% due 2010	12,300	12,300
Pollution control revenue bonds at 7.5% due 2024	12,200	12,200
Other	3,911	2,855
	28,411	27,355
Project financing debt:		
Floating-rate term loans at a weighted average rate of 8.05% at December 31, 2000 due 2009 through 2010 (a)	159,296	-
Total long-term debt	321,052	162,030
Less current maturities	(13,960)	(1,330)
Net long-term debt	$307,092	$160,700

- ---------------

(a) Approximately 80 percent of the December 31, 2000 balance has been hedged with an interest rate swap moving the floating rates to fixed rates with a weighted average interest rate of 7.69 percent (see Note 2-Price Risk Management).

Substantially all of the Company's utility property is subject to the lien of the indenture securing its first mortgage bonds. First mortgage bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Project financing debt is non-recourse debt collateralized by a mortgage on each respective project's land and facilities, leases and rights, including rights to receive payments under long-term purchase power contracts.

Certain debt instruments of the Company and its subsidiaries contain restrictive covenants, all of which the Company and its subsidiaries are in compliance with at December 31, 2000. Scheduled maturities for the next five years are: $14.0 million in 2001, $30.0 million in 2002, $16.0 million in 2003, $16.4 million in 2004, and $17.6 million in 2005.

(7) NOTES PAYABLE

The Company had committed lines of credit with various banks of $290.0 million at December 31, 2000 and $115.0 million at December 31, 1999, which were available to support bank borrowings or to provide for letters of credit. There were $211.0 million of borrowings and $20.6 million of letters of credit issued under these lines of credit at December 31, 2000, and there were $96.6 million of borrowings and no letters of credit issued at December 31, 1999. The Company has no compensating balance requirements associated with these lines of credit. The lines of credit are subject to periodic review and renewal during the year by the banks.

In addition to the above lines of credit, Enserco Energy, Inc. has a $90.0 million uncommitted, discretionary line of credit to provide support for the purchases of natural gas. The Company and its subsidiaries provide no guarantee to the lender. At December 31, 2000 and 1999, there were outstanding letters of credit issued under the facility of $69.8 million and $19.9 million respectively, with no borrowing balances on the facility.

In addition to the above lines of credit, Black Hills Energy Resources, Inc. has a $25.0 million uncommitted, discretionary credit facility. The transactional line of credit provides credit support for the purchases of crude oil of Black Hills Energy Resources. The Company and its subsidiaries provide no guarantee to the lender. At December 31, 2000 and 1999, Black Hills Energy Resources, Inc. had letters of credit outstanding of $8.5 million and $13.2 million, respectively and no balance outstanding on the overdraft line.

Our credit facilities contain restrictive covenants and include commitment fees ranging from .125 percent to .375 percent; our credit facilities with ABN AMRO Bank, NV also include utilization fees of .75 percent on the amount by which facility loans exceed 50 percent of the total facility commitment. The Company and its subsidiaries had complied with all the covenants at December 31, 2000.

Interest rates under the facility borrowings vary and are based, at the option of the Company at the time of the loan origination, on either (i) a prime based borrowing rate varying from prime rate (9.5 percent at December 31, 2000) to prime rate plus 1.5 percent, or (ii) on the London Interbank Offered Rate (LIBOR) (6.5 percent for a one-month LIBOR at December 31, 2000) based borrowings rates varying from LIBOR plus .625 percent to LIBOR plus 1.375 percent.

(8) FAIR VALUE OF FINANCIAL INSTRUMENTS

Cash of the Company is invested in money market investments such as municipal put bonds, money market preferreds, commercial paper, Eurodollars and certificates of deposit.

The following methods and assumptions were used to estimate the fair value of each class of the Company's financial instruments.

Cash and Cash Equivalents

The carrying amount approximates fair value due to the short maturity of these instruments.

Available for Sale Securities

The fair value of the Company's investments equals the quoted market price when available and a quoted market price for similar securities if a quoted market price is not available. The Company has classified all of its marketable securities as available-for-sale as of December 31, 2000 and 1999. An unrealized loss on the Company's investments of $0.8 million was recorded as of December 31, 2000. At December 31, 1999 fair value approximated cost.

Long-Term Debt

The fair value of the Company's long-term debt is estimated based on quoted market rates for utility debt instruments having similar maturities and similar debt ratings. The Company's outstanding bonds are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for the Company to call and refinance the bonds.

The estimated fair values of the Company's financial instruments are as follows:

	2000 (in thousands) Carrying Amount	Fair Value
Cash and cash equivalents	$ 24,913	$ 24,913
Securities available for sale	2,113	2,113
Long-term debt	321,052	337,446

	1999 (in thousands) Carrying Amount	Fair Value
Cash and cash equivalents	$ 16,482	$ 16,482
Securities available for sale	7,586	7,586
Long-term debt	162,030	165,958

(9) WYODAK PLANT

The Company owns a 20 percent interest and Pacific Power owns an 80 percent interest in the Wyodak plant (Plant), a 330 megawatt coal-fired electric generating station located in Campbell County, Wyoming. Pacific Power is the operator of the Plant. The Company receives 20 percent of the Plant's capacity and is committed to pay 20 percent of its additions, replacements and operating and maintenance expenses. As of December 31, 2000, the Company's investment in the Plant included $71.8 million in electric plant and $22.4 million in accumulated depreciation. The Company's share of direct expenses of the Plant was $5.6 million, $4.9 million and $5.8 million for the years ended December 31, 2000, 1999 and 1998, respectively, and is included in the corresponding categories of operating expenses in the accompanying consolidated statements of income. Wyodak Resources supplies coal to the Plant under an agreement expiring in 2013 with a Pacific Power option to renew the agreement for an additional 10 years. This coal supply agreement is collateralized by a mortgage on and a security interest in some of Wyodak Resources' coal reserves. At December 31, 2000, approximately 17,966,000 tons of coal were covered under this agreement. Wyodak Resources' sales to the Plant were $23.2 million, $24.9 million and $23.2 million, for the years ended December 31, 2000, 1999 and 1998, respectively.

(10) COMMITMENTS AND CONTINGENCIES

Pacific Power's Power Sales Agreement

In 1983, the Company entered into a 40 year power agreement with Pacific Power providing for the purchase by the Company of 75 megawatts of electric capacity and energy from Pacific Power's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 megawatts (5 megawatts per year starting in 2000). The price paid for the capacity and energy is based on the operating costs of one of Pacific Power's coal-fired electric generating plants. Costs incurred under this agreement were $14.6 million, $17.8 million and $17.5 million in 2000, 1999 and 1998, respectively.

Reclamation

Under its mining permit, Wyodak Resources is required to reclaim all land where it has mined coal reserves. The cost of reclaiming the land is accrued as the coal is mined. While the reclamation process takes place on a continual basis, much of the reclamation occurs over an extended period after the area is mined. Approximately $0.7 million is charged to operations as reclamation expense annually. As of December 31, 2000, accrued reclamation costs were approximately $17.7 million.

Legal Proceedings

On August 14, 2000, Wyodak Resources Development Corp. ("Wyodak") initiated an action against PacifiCorp as it concerns the Further Restated and Amended Coal Supply Agreement, dated as of May 5, 1987 ("Coal Supply Agreement"). The action has been filed in the United States District Court for the District of Wyoming as Case No. 00CV155-B. Wyodak alleges that PacifiCorp has failed and refused to make complete payment to Wyodak for coal sold under the Coal Supply Agreement, and there was at that time approximately $5.0 million outstanding and allegedly due Wyodak from PacifiCorp. Wyodak alleged that PacifiCorp's actions constitute a breach of contract and asked for the appropriate monetary relief.

On August 31, 2000, PacifiCorp answered the Wyodak Complaint and additionally brought a counterclaim against Wyodak and Black Hills Corporation. In its action, PacifiCorp alleged that as a result of Wyodak's actions as it concerns its billings under the Coal Supply Agreement, PacifiCorp was entitled to cancel and terminate the Coal Supply Agreement and Coal Handling Agreement, as well as the recovery of damages. PacifiCorp alleged that Wyodak had not properly adjusted upward and downward the components which make up the coal price under the Coal Supply Agreement, and as a result PacifiCorp had been overbilled appproximately $35.0 million to $40.0 million and that Wyodak continued to overcharge PacifiCorp under the Coal Supply Agreement and the Coal Handling Agreement. PacifiCorp further alleged that the overcharges would result in additional overcharges of approximately $150.0 million through the balance of the term of the Coal Supply Agreement, which expires in June of 2013. In its action, PacifiCorp sought not only to cancel and terminate the contract but also to discharge and excuse any further obligation under the same, as well as recovery of damages as set forth above.

Management is of the opinion that Wyodak has properly billed PacifiCorp under the terms of the Coal Supply Agreement and Coal Handling Agreement and PacifiCorp's withholding of payment constitutes a breach of contract on their part. Although it is impossible to predict whether or not Black Hills Corporation and Wyodak will ultimately be successful in defending the claim or, if not, what the impact might be, management believes that the disposition of this matter will not have a material adverse effect on the Company's consolidated results of operations.

In addition, the Company is subject to various legal proceedings and claims which arise in the ordinary course of operations. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect the consolidated financial position or results of operations of the Company.

(11) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension and Other Postretirement Plans

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of Black Hills Power, Wyodak Resources Development Corp., Black Hills Exploration and Production and Daksoft who meet certain eligibility requirements. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Company's funding policy is in accordance with the federal government's funding requirements. The Plan's assets are held in trust and consist primarily of equity securities and cash equivalents.

Net pension income for the Plan was as follows:

	2000	1999	1998
		(in thousands)	
Service cost	$ 967	$ 1,174	$ 895
Interest cost	2,885	2,598	2,406
Estimated return on assets	(5,257)	(4,162)	(4,146)
Amortization of transition amount	(90)	(90)	(90)
Amortization of prior service cost	231	89	89
Recognized net actuarial gain	(537)	-	(272)
Net pension income	$(1,801)	$ (391)	$(1,118)
Actuarial assumptions:			
Discount rate	7.5%	6.75%	7.5%
Expected long-term rate of return on assets	10.5%	10.5%	10.5%
Rate of increase in compensation levels	5.0%	5.0%	5.0%

A reconciliation of the beginning and ending balances of the projected benefit obligation is as follows:

	2000	1999
	(in thousands)	
Beginning projected benefit obligation	$39,615	$39,490
Service cost	967	1,174
Interest cost	2,885	2,598
Actuarial losses	(48)	(3,590)
Benefits paid	(2,105)	(1,903)
Plan amendments	-	1,846
Net increase	1,699	125
Ending projected benefit obligation	$41,314	$39,615

A reconciliation of the fair value of plan assets as of October 1 of each year is as follows:

	2000	1999
	(in thousands)	
Beginning market value of plan assets	$51,212	$40,638
Benefits paid	(2,105)	(1,903)
Investment income	7,453	12,477
Ending market value of plan assets	$56,560	$51,212

Funding information for the Plan as of October 1 each year was as follows:

	2000	1999
	(in thousands)	
Fair value of plan assets	$56,560	$51,212
Projected benefit obligation	(41,314)	(39,615)
Funded status	15,246	11,597
Unrecognized:		
Net gain	(13,812)	(12,105)
Prior service cost	2,054	2,285
Transition asset	-	(90)
Prepaid pension cost	$ 3,488	$ 1,687
Accumulated benefit obligation	$33,374	$31,914

The Company has various supplemental retirement plans for outside directors and key executives of the Company. The plans are nonqualified defined benefit plans. Expenses recognized under the plans were $0.5 million, $0.4 million and $0.4 million in 2000, 1999 and 1998, respectively.

Employees who are participants in the Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service to the Company are entitled to postretirement healthcare benefits coverage. These benefits are subject to premiums, deductibles, copayment provisions and other limitations. The Company may amend or change the plan periodically. The Company is not pre-funding its retiree medical plan.

The net periodic postretirement cost was as follows:

	2000	1999	1998
		(in thousands)	
Service cost	$282	$225	$135
Interest cost	523	362	290
Amortization of transition obligation	150	150	150
(Gain)/loss	68	1	(42)
	$1,023	$738	$533

Funding information as of October 1 was as follows:

	2000	1999
	(in thousands)	
Accumulated postretirement benefit obligation:		
Retirees	$2,478	$2,608
Fully eligible active participants	1,203	1,195
Other active participants	3,172	3,278
Unfunded accumulated postretirement benefit obligation	6,853	7,081
Unrecognized net loss	(1,001)	(1,667)
Unrecognized transition obligation	(1,797)	(1,947)
Accrued postretirement cost	$4,055	$3,467

For measurement purposes, an 8.5 percent annual rate of increase in healthcare benefits was assumed for 2000; the rate was assumed to decrease gradually to 6 percent in 2005 and remain at that level thereafter. The healthcare cost trend rate assumption has a significant effect on the amounts reported. A one percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.2 million or 21.8 percent and the net periodic postretirement cost $0.2 million or 24.1 percent. A one percent decrease would reduce the service and interest cost by $0.1 million or 16.9 percent and decrease the net periodic postretirement cost $0.2 million or 18.6 percent. The weighted-average discount rate used in determining the accumulated postretirement benefit obligation was 7.5 percent.

Defined Contribution Plan

The Company also sponsors a 401(k) savings plan for eligible employees. Participants elect to invest up to 20 percent of their eligible compensation on a pre-tax basis. Effective January 1, 2000 (May 1, 2000 for employees covered by the collective bargaining agreement), the Company provides a matching contribution of 100 percent of the employee's tax-deferred contribution up to a maximum 3 percent of the employee's eligible compensation. Matching contributions vest at 20 percent per year and are fully vested when the participant has 5 years of service with the Company. The Company's matching contributions totaled $0.6 million for 2000.

(12) INCOME TAXES

Income tax expense for the years indicated was:

	2000	1999	1998
		(in thousands)	
Current	$28,421	$13,498	$14,243
Deferred	2,576	2,931	(1,886)
Tax credits, net	(639)	(640)	(649)
	$30,358	$15,789	$11,708

The temporary differences which gave rise to the net deferred tax liability at December 31, 2000 and 1999 were as follows:

December 31, 2000	Assets	Liabilities	Net Deferred Income Tax Asset (Liability)
		(in thousands)	
Accelerated depreciation and other plant-related differences	$ 5,393	$63,559	$(58,166)
Regulatory asset	1,621	-	1,621
Regulatory liability	-	1,447	(1,447)
Unamortized investment tax credits	886	-	886
Mining development and oil exploration	3,605	8,450	(4,845)
Employee benefits	3,308	1,347	1,961
Other	3,711	6,400	(2,689)
	$18,524	$81,203	$(62,679)

December 31, 1999	Assets	Liabilities	Net Deferred Income Tax Asset (Liability)
		(in thousands)	
Accelerated depreciation and other plant-related differences	$ -	$48,223	$(48,223)
Regulatory asset	1,792	-	1,792
Regulatory liability	-	1,380	(1,380)
Unamortized investment tax credits	1,058	-	1,058
Mining development and oil exploration	3,605	6,893	(3,288)
Employee benefits	2,833	695	2,138
Other	2,184	1,949	235
	$11,472	$59,140	$(47,668)

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2000	1999	1998
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	1.4	-	-
Amortization of investment tax credits	(1.0)	(0.9)	(1.3)
Tax-exempt interest income	-	(0.5)	(1.1)
Percentage depletion in excess of cost	(1.1)	(1.6)	(1.7)
Other	2.2	(2.1)	0.3
	36.5%	29.9%	31.2%

(13) BUSINESS SEGMENTS

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2000, substantially all of the Company's operations and assets are located within the United States. The Company's operations are conducted through six business segments that include: Electric, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana; Independent Energy consisting of: Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; Oil and Gas, which produces, explores and operates oil and gas interests located in the Rocky Mountain region, Texas, California and other states; Fuel Marketing, which markets natural gas, oil, coal and related services to customers in the East Coast, Midwest, Southwest, Rocky Mountain, West Coast and Northwest regions markets; Independent Power, which produces and sells power to wholesale customers; and Communications and Others, which primarily markets communications and software development services.

Segment information follows the same accounting policies as described in Note 1 - - BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES. Segment information included in the accompanying Consolidated Balance Sheets and Consolidated Statements of Income is as follows (in thousands):

ASSETS		Independent Energy						
	Electric	Mining	Oil and Gas	Fuel Marketing	Independent Power	Communications & Others	Eliminations	Total
At December 31, 2000								
Current assets	$ 133,542	$167,820	$ 3,452	$ 330,352	$ 25,645	$ 13,215	$ (255,016)	$ 419,010
Total assets	627,930	251,136	36,396	346,333	375,811	132,724	(450,010)	1,320,320
At December 31, 1999								
Current assets	$ 93,837	$ 57,427	$ 1,988	$ 84,867	$ 52,471	$ 9,698	$ (113,931)	$ 186,357
Total assets	522,285	136,372	29,381	99,064	52,690	72,711	(244,011)	668,492
At December 31, 1998								
Current assets	$ 43,760	$ 25,872	$ 1,335	$ 77,402	$ 4	$ 6,067	$ (13,960)	$ 140,480
Total assets	451,404	93,480	26,666	86,300	57	18,441	(116,931)	559,417

		Independent Energy						
Year ended December 31, 2000	Electric	Mining	Oil and Gas	Fuel Marketing	Independent Power	Communications & Others	Eliminations	Total
Electric revenues	$ 173,308	$ -	$ -	$ -	$ -	$ -	$ -	$ 173,308
Coal revenues	-	30,530	-	37,099	-	-	-	67,629
Gas revenues	-	-	9,335	871,296	-	-	(14,320)	866,311
Oil revenues	-	-	7,211	458,575	-	-	-	465,786
Other operating revenues	-	-	3,782	-	39,660	11,371	(4,011)	50,802
Total operating revenues	$ 173,308	$ 30,530	$ 20,328	$1,366,970	$ 39,660	$ 11,371	$ (18,331)	$1,623,836
Depreciation, depletion and amortization	$ 14,966	$3,525	$ 4,071	$ 644	$ 3,646	$ 6,012	$ -	$ 32,864
Operating income (loss)	68,208	8,794	7,906	23,774	20,374	(14,306)	-	114,750
Interest expense	17,411	8,006	372	535	11,911	6,350	(14,243)	30,342
Income taxes (benefit)	19,469	2,660	2,609	9,323	3,154	(6,857)	-	30,358
Net income (loss) available for common	37,100	7,173	4,992	14,009	3,241	(12,557)	(1,188)	52,770
Property additions, investments and acquisition of net assets	25,257	2,419	9,259	(3)	81,335*	58,922	-	177,189

*Excludes the non-cash acquisition of Indeck Capital, Inc. as described in Note 14.

Year ended December 31, 1999	Electric	Mining	Oil and Gas (Independent Energy)	Fuel Marketing (Independent Energy)	Independent Power (Independent Energy)	Communications & Others	Eliminations	Total
Electric revenues	$ 133,222	$ -	$ -	$ -	$ -	$ -	$ -	$ 133,222
Coal revenues	-	31,095	-	39,212	-	-	-	70,307
Gas revenues	-	-	5,399	382,809	-	-	-	388,208
Oil revenues	-	-	4,676	192,207	-	-	-	196,883
Other operating revenues	-	-	2,977	-	-	3,423	(3,145)	3,255
Total operating revenues	$ 133,222	$ 31,095	$ 13,052	$ 614,228	$ -	$ 3,423	$ (3,145)	$ 791,875
Depreciation, depletion and amortization	$ 15,552	$ 3,259	$ 2,953	$ 2,757	$ -	$ 546	$ -	$ 25,067
Operating income (loss)	52,286	12,606	3,978	(2,248)	(157)	(4,574)	-	61,891
Interest expense	13,830	1,260	568	719	111	1,172	(2,200)	15,460
Income taxes (benefit)	12,446	3,439	968	50	(58)	(1,056)	-	15,789
Net income (loss) available for common	27,362	9,715	2,462	(185)	(109)	(1,263)	(915)	37,067
Property additions, investments and acquisition of net assets	31,911	5,422	9,968	5,947	52,319	49,042	-	154,609

Year ended December 31, 1999	Electric	Mining	Oil and Gas (Independent Energy)	Fuel Marketing (Independent Energy)	Independent Power (Independent Energy)	Communications & Others	Eliminations	Total
Electric revenues	$ 129,236	$ -	$ -	$ -	$ -	$ -	$ -	$ 129,236
Coal revenues	-	31,413	-	12,924	-	-	-	44,337
Gas revenues	-	-	4,073	375,136	-	-	-	379,209
Oil revenues	-	-	5,131	117,185	-	-	-	122,316
Other operating revenues	-	-	3,358	798	-	2,437	(2,437)	4,156
Total operating revenues	$ 129,236	$ 31,413	$ 12,562	$ 506,043	$ -	$ 2,437	$ (2,437)	$ 679,254
Depreciation, depletion and amortization	$ 14,881	$ 3,252	$ 18,760**	$ 690	$ -	$ -	$ -	$ 37,583
Operating income (loss)	49,896	12,723	(12,340)**	41	-	(1,087)	-	49,233
Interest income	13,572	10	355	731	-	39	-	14,707
Income taxes (benefit)	12,612	4,126	(4,689)**	(116)	(64)	(161)	-	11,708
Net income (loss) available for common	24,825	9,750	(7,976)**	(346)	(118)	(226)	(101)	25,808
Property additions, investments and acquisition of net assets	11,451	1,406	10,169	2,384	-	1,815	-	27,225

**Includes the impact of a $13.5 million pre-tax write-down of certain oil and natural gas properties.

(14) ACQUISITIONS

On July 7, 2000, the Company acquired Indeck Capital, Inc. and merged it into Black Hills Energy Capital, Inc. The new entity owns varying interests in 14 operating independent power plants in California, New York, Massachusetts, Colorado and Idaho totaling approximately 350 megawatts.

The acquisition was a stock transaction with the Company issuing 1,536,747 shares of common stock to the shareholders of Indeck priced at $21.98 per share (approximately 7 percent of the Company's common stock after the transaction), along with $4 million in preferred stock, resulting in a purchase price of approximately $37.8 million. Additional consideration, consisting of common and preferred stock, may be paid in the form of an earn-out over a four-year period. The earn-out consideration will be based on the acquired company's earnings during such period and cannot exceed $35.0 million in total. Additional consideration paid out under the earn-out will be recorded as an increase to goodwill.

The acquisition has been accounted for under the purchase method of accounting and, accordingly, the purchase price has been allocated to the acquired assets and liabilities based on estimates of the fair values of the assets purchased and the liabilities assumed as of the date of acquisition. Fair values in the allocation include assets acquired of approximately $151.1 million (excluding goodwill) and liabilities assumed of approximately $138.7 million. As of December 31, 2000, the purchase price and related acquisition costs exceeded the fair values assigned to net tangible assets by approximately $25.4 million, which was recorded as goodwill and is being amortized over 25 years on a straight-line basis.

Prior to the closing of the Indeck Capital transaction, there was no material relationship between its shareholders and the Company or any of its affiliates, any director or officer of the Company or any of their associates, except that the Company through its subsidiaries and Indeck Capital jointly owned Black Hills Colorado, LLC and both parties held interests in Indeck North American Power Partners, L.P. and Indeck North American Power Fund, L.P. Black Hills Colorado owns 111 megawatts of combustion turbine generating facilities in the Front Range of Colorado.

In addition, the Company made several step-acquisitions resulting in consolidation of $169.5 million of assets and $138.8 million of liabilities. The related transactions are as follows:

- Through various transactions, acquired an additional 27.11 percent interest in Indeck North American Power Fund, L.P. and an additional 46.66 percent interest in Indeck North American Power Partners, L.P., for approximately $13.0 million in cash.

- Acquired a 39.6 percent interest in each of Northern Electric Power Company, L.P. and South Glens Falls Limited Partnership for approximately $4.2 million in cash.

- Acquired substantially all of the partnership interests in Middle Falls Limited Partnership, Sissonville Limited Partnership and New York State Dam Limited Partnership for approximately $12.9 million in cash.

Operating activities of the above acquired companies have been included in the accompanying consolidated financial statements since their respective acquisition dates. The following unaudited pro forma condensed results of operations presents the effect of the acquisitions as if they had occurred on January 1, 1999. The pro forma financial data is provided for informational purposes only and does not purport to be indicative of the results that would have been obtained if the acquisitions had been effected on January 1, 1999. The pro forma financial information reflects the amortization of the excess purchase price over the fair value of net assets acquired and the income tax effect thereof for the years ended December 31, 2000 and 1999 as follows:

	2000	1999
	(Unaudited, in thousands, except per share amounts)	
Revenues	$1,668,851	$840,891
Operating income	$139,053	$73,900
Net income available for common	$57,542	$34,310
Net income per share: Basic	$2.47	$1.49
Diluted	$2.45	$1.49

(15) OIL AND GAS RESERVES (Unaudited)

Black Hills Exploration and Production has interests in 639 producing oil and gas properties in seven states. Black Hills Exploration and Production also holds leases on approximately 185,926 net undeveloped acres.

The following table summarizes Black Hills Exploration and Production's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2000, 1999 and 1998, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering company selected by the Company. Such reserve estimates are based upon a number of variable factors and assumptions which may cause these estimates to differ from actual results.

	2000		1999		1998	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in thousands of barrels of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	4,109	19,460	2,368	15,952	2,495	9,052
Production	(352)	(3,285)	(309)	(2,801)	(353)	(2,068)
Additions	625	4,228	376	7,718	1,149	10,721
Property sales	-	-	(164)	(66)	-	-
Revisions to previous estimates	31	(1,999)	1,838	(1,343)	(923)	(1,753)
Balance at end of year	4,413	18,404	4,109	19,460	2,368	15,952
Proved developed reserves at end of year included above	3,047	16,418	2,819	14,391	1,463	10,041
Year-end prices	$26.80	$9.78	$24.28	$1.99	$9.16	$1.93

In December 1998, Black Hills Exploration and Production recognized a $13.5 million pre-tax loss related to a write-down of oil and gas properties. The write-down was primarily due to historically low crude oil prices, lower natural gas prices and decline in value of certain unevaluated properties.

(16) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following table sets forth selected unaudited historical operating results and market data for each quarter of 2000 and 1999.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
2000:				
Operating revenues	$247,959	$336,978	$453,231	$585,668
Operating income	16,872	15,200	42,519	40,159
Net income available for common stock	9,061	8,061	16,285	19,363
Earnings per common share: Basic	0.42	0.38	0.71	0.84
Diluted	0.42	0.38	0.71	0.83
Dividends paid per share	0.27	0.27	0.27	0.27
Common stock prices				
High	25.19	25.19	30.13	46.06
Low	20.44	20.88	22.00	27.00
1999:				
Operating revenues	$168,201	$186,195	$219,779	$217,700
Operating income	15,980	13,786	16,675	15,450
Net income available for common stock	9,035	7,763	9,725	10,544
Earnings per common share: Basic	0.42	0.36	0.45	0.50
Diluted	0.42	0.36	0.45	0.50
Dividends paid per share	0.26	0.26	0.26	0.26
Common stock prices				
High	26.50	23.88	25.63	23.31

Low	21.00	21.00	22.19	20.31

(17) SUBSEQUENT EVENT (Unaudited)

On March 8, 2001, Black Hills Energy Capital, Inc., the Company's independent power subsidiary announced it had signed a definitive agreement to purchase a 240 megawatt gas-fired turbine generation facility (Fountain Valley) located near Colorado Springs, Colorado from Enron Corporation. The transaction is expected to close around March 31, 2001.

The Fountain Valley facility features six LM-6000 simple-cycle, gas-fired turbines, a technology identical to existing Company facilities in Colorado and Wyoming. All necessary permitting has been approved and the plant is expected to phase in its generation capacity beginning in May 2001. The Company also announced that it has signed an 11-year contract with Public Service of Colorado to utilize the plant for peaking purposes. The contract is a tolling arrangement in which the Company assumes no fuel costs. The cost of the project is expected to be approximately $175 million. The Company expects to finance the project primarily with non-recourse debt and negotiations are presently under way with certain lenders.

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

No change of accountants or disagreements on any matter of accounting principles or practices or financial statement disclosure have occurred.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information regarding the directors of the Company is incorporated herein by reference to the Proxy Statement for the Annual Shareholders' Meeting to be held May 30, 2001.

EXECUTIVE OFFICERS

Daniel P. Landguth, age 54, was elected Chairman of the Board and Chief Executive Officer in January 1991. Mr. Landguth also currently chairs the Executive Committee. He has 30 years of experience with Black Hills. Mr. Landguth holds a B.S. degree in Electrical Engineering from the South Dakota School of Mines and Technology.

Everett E. Hoyt, age 61, has been President and Chief Operating Officer since February 2001. Since 1989, he has been President and Chief Operating Officer of our regulated utility business - a role he continues to play. Mr. Hoyt was elected to the Board of Directors in 1991. Prior to joining us, Mr. Hoyt was employed by NorthWestern Corporation for 16 years where he served as Senior Vice President-Legal and as a member of the Board of Directors. He holds a B.S. degree in Mechanical Engineering from the South Dakota School of Mines and Technology and a J.D. from the University of South Dakota School of Law.

Gary R. Fish, age 42, has been the President and COO of our Independent Energy Group since September 1999. Prior to that, he served in several development and accounting officer positions for us since August 1988. Mr. Fish holds a B.S. in Business Administration from the University of South Dakota and is a certified public accountant.

Ronald D. Schaible, age 56, has been Senior Vice President of Communications of Black Hills Corporation and Vice President and General Manager of Black Hills FiberCom since October 1998. Mr. Schaible has more than 25 years experience in the telecommunications industry. From 1995 to 1998, he was Vice President and General Manager of the Kansas City and Missouri subsidiaries of Brooks Fiber Properties. Mr. Schaible was responsible for both network construction and operations in Kansas City. He holds a B.S. in Electrical Engineering from South Dakota State University.

Mark T. Thies, age 37, has been our Senior Vice President and Chief Financial Officer since March 2000. From May 1997 to March 2000, he was our Controller. From 1990 to 1997, Mr. Thies served in a number of accounting positions with InterCoast Energy Company, an unregulated energy company and a wholly-owned subsidiary of MidAmerican Energy Holdings Company. Mr. Thies holds B.A.s in Accounting and Business Administration from Saint Ambrose College and is a certified public accountant.

Thomas M. Ohlmacher, age 49, has been the Senior Vice President-Power Supply and Power Marketing since January 30, 2001 and Vice President - Power Supply since August 1994. Prior to that, he held several positions with our company since 1974. Mr. Ohlmacher holds a B.S. in Chemistry from the South Dakota School of Mines and Technology.

James M. Mattern, age 46, has been the Senior Vice President-Corporate Administration since September 1999, and was Vice President-Corporate Administration from January 1994 to September 1999. From 1997 to 1999, he was also Assistant to the CEO. Mr. Mattern has 12 years of experience with us. He holds a B.S. in Social Sciences and an M.S. in Administration from Northern State University.

Steven J. Helmers, age 44, has been our General Counsel and Corporate Secretary since January 2001. Prior to joining us, Mr. Helmers was a shareholder with the Rapid City, South Dakota law firms of Truhe, Beardsley, Jensen, Helmers & VonWald, from 1997 to January 2001, and Lynn, Jackson, Schultz & Lebrun, P.C., from 1983 to 1997. He holds a J.D. from the University of South Dakota School of Law.

Roxann R. Basham, age 39, has been our Vice President-Controller since March 2000. From December 1997 to March 2000, she was Vice President-Finance and Secretary/Treasurer. From 1993 until December 1997, she served as our Secretary/Treasurer, and has a total of 16 years of experience with us. She holds a B.S. in Business Administration from the University of South Dakota and is a certified public accountant.

David R. Emery, age 38, has been our Vice President-Fuel Resources since January 1997. From June 1993 to January 1997, he was General Manager of Black Hills Exploration and Production. Mr. Emery has 12 years of experience with us. He holds a B.S. in Petroleum Engineering from the University of Wyoming and an M.S. in Business Administration from the University of South Dakota.

Kyle D. White, age 41, has been Vice President - Corporate Affairs since January 30, 2001 and Vice President-Marketing and Regulatory Affairs since July 1998. Mr. White served as Director-Strategic Marketing and Sales from 1993 to January 1998 and Vice President-Energy Services from January 1998 to July 1998. He has a total of 18 years of experience with us. Mr. White holds a B.S. and M.S. in Business Administration from the University of South Dakota.

ITEM 11. EXECUTIVE COMPENSATION

Information regarding management remuneration and transactions is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 30, 2001.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information regarding the security ownership of certain beneficial owners and management is incorporated herein by reference to our Proxy statement for the Annual Shareholders' Meeting to be held May 30, 2001.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information regarding certain relationships and related transactions is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 30, 2001.

PART IV

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

(a) 1. Consolidated Financial Statements

Financial statements required by Item 14 are listed in the index included in Item 8 of Part II.

2. Schedules

All schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements incorporated by reference in the Form 10-K.

3. Exhibits

Exhibit Number	Description
2*	Plan of Exchange Between Black Hills Corporation and Black Hills Holding Corporation (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.1*	Articles of Incorporation of the Registrant (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.2*	Articles of Amendment of the Registrant (filed as an exhibit to the Registrant's Form 8-K filed on December 26, 2000).
3.3*	Bylaws of the Registrant (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.4*	Statement of Designations, Preferences and Relative Rights and Limitations of No Par Preferred Stock, Series 2000-A of the Registrant (filed as an exhibit to the Registrant's Form 8-K filed on December 26, 2000).
4.1*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Power, Inc. dated as of September 1, 1999 (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
4.2	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share.
10.1*	Agreement for Transmission Service and the Common Use of Transmission Systems dated January 1, 1986, among Black Hills Power, Inc., Basin Electric Power Cooperative, Rushmore Electric Power Cooperative, Inc., Tri-County Electric Association, Inc., Black Hills Electric Cooperative, Inc. and Butte Electric Cooperative, Inc. (filed as Exhibit 10(d) to the Registrant's Form 10-K for 1987).
10.2*	Restated and Amended Coal Supply Agreement for NS #2 dated February 12, 1993 (filed as Exhibit 10(c) to the Registrant's Form 10-K for 1992).
10.3*	Coal Leases between Wyodak Resources Development Corp. and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.4*	Further Restated and Amended Coal Supply Agreement dated May 5, 1987 between Wyodak Resources Development Corp. and Pacific Power & Light Company (filed as Exhibit 10(k) to the Registrant's Form 10-K for 1987).
10.5*	Second Restated and Amended Power Sales Agreement dated September 29, 1997, between PacifiCorp and Black Hills Power, Inc. (filed as Exhibit 10(e) to the Registrant's Form 10-K for 1997).

10.6*	Coal Supply Agreement for Wyodak Unit #2 dated February 3, 1983, and Ancillary Agreement dated February 3, 1982, between Wyodak Resources Development Corp., Pacific Power & Light Company and Black Hills Power, Inc. (filed as Exhibit 10(o) to the Registrant's Form 10-K for 1983). Amendment to Agreement for Coal Supply for Wyodak #2 dated May 5, 1987 (filed as Exhibit 10(o) to the Registrant's Form 10-K for 1987).
10.7*	Reserve Capacity Integration Agreement dated May 5, 1987, between Pacific Power & Light Company and Black Hills Power, Inc. (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1987).
10.8*	Marketing, Capacity and Storage Service Agreement between Black Hills Power, Inc. and PacifiCorp dated September 1, 1995 (filed as Exhibit 10(ag) to the Registrant's Form 10-K for 1995).
10.9*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between Wyodak Resources Development Corp. and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
10.10*	Rate Freeze Extension (filed as Exhibit 10(t) to the Registrant's Form 10-K for 1999).
10.11 +	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated January 6, 2000.
10.12 +	First Amendment to the Pension Equalization Plan of Black Hills Corporation dated January 30, 2001.
10.13 +	Black Hills Corporation Nonqualified Deferred Compensation Plan dated June 1, 1999.
10.14 +	Black Hills Corporation 1999 Stock Option Plan.
10.15*+	Agreement for Supplemental Pension Benefit for Everett E. Hoyt dated January 20, 1992 (flied as Exhibit 10(gg) to the Registrant's Form 10-K for 1992).
10.16*+	Change in Control Agreements for various officers (filed as Exhibit 10(af) to the Registrant's Form 10-K for 1995).
10.17*+	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1997).
10.18*+	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registration's Form 10-K for 1997).
10.19*+	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1999).
10.20*	Agreement and Plan of Merger, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 2 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.21*	Addendum to the Agreement and Plan of Merger, dated as of April 6, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 3 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.22*	Supplemental Agreement Regarding Contingent Merger Consideration, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 4 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.23*	Supplemental Agreement Regarding Restructuring of Certain Qualifying Facilities (Exhibit 5 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.24*	Addendum to the Agreement and Plan of Merger, dated as of June 30, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 6 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.25*	Registration Rights Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 7 to Schedule 13D

	filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.26*	Shareholders Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 8 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Public Accountants.
23.2	Consent of Petroleum Engineer and Geologist.

- ----------

* Previously filed as part of the filing indicated and incorporated by reference herein.

\+ Indicates a board of director or management compensatory plan.

(b) Reports on Form 8-K

We have filed the following Reports on Form 8-K since September 30,2000.

Form 8-K filed December 22, 2000.

Reported the formation of the holding company structure through a "Plan of Exchange" between Black Hills Corporation and Black Hills Holding Corporation on December 22, 2000.

Form 8-K dated December 5, 2000, filed January 12, 2001.

Reported Adirondack Hydro Development Corporation, an indirect subsidiary of the Registrant, acquired a 19.8 percent limited partnership interest in each of Northern Electric Power Company, L.P. and South Glens Falls Limited Partnership from Allstate Insurance Company and Allstate Life Insurance Company.

Form 8-K/A1 dated February 16, 2001.

Filed the financial statement and exhibits for the Form 8-K filed on January 12, 2001.

(c) See (a) 3. Exhibits above.

(d) See (a) 2. Schedules above.

SIGNATURES

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

BLACK HILLS CORPORATION

By DANIEL P. LANDGUTH
Daniel P. Landguth, Chairman
and Chief Executive Officer

Dated: March 19, 2001

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 and on the dates indicated.

DANIEL P. LANDGUTH Daniel P. Landguth, Chairman, and Chief Executive Officer	Director and Principal Executive Officer	March 19, 2001
MARK T. THIES Mark T. Thies, Senior Vice President and Chief Financial Officer	Principal Financial Officer	March 19, 2001
ROXANN R. BASHAM Roxann R. Basham, Vice President-Controller, and Assistant Secretary	Principal Accounting Officer	March 19, 2001
ADIL M. AMEER Adil M. Ameer	Director	March 19, 2001
BRUCE B. BRUNDAGE Bruce B. Brundage	Director	March 19, 2001
DAVID C. EBERTZ David C. Ebertz	Director	March 19, 2001
GERALD R. FORSYTHE Gerald R. Forsythe	Director	March 19, 2001
JOHN R. HOWARD John R. Howard	Director	March 19, 2001
EVERETT E. HOYT Everett E. Hoyt (President and Chief Operating Officer of Black Hills Corporation)	Director and Officer	March 19, 2001
KAY S. JORGENSEN Kay S. Jorgensen	Director	March 19, 2001
DAVID S. MANEY David S. Maney	Director	March 19, 2001
THOMAS J. ZELLER Thomas J. Zeller	Director	March 19, 2001

INDEX TO EXHIBITS

Exhibit Number	Description
2*	Plan of Exchange Between Black Hills Corporation and Black Hills Holding Corporation (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.1*	Articles of Incorporation of the Registrant (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.2*	Articles of Amendment of the Registrant (filed as an exhibit to the Registrant's Form 8-K filed on December 26, 2000).
3.3*	Bylaws of the Registrant (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.4*	Statement of Designations, Preferences and Relative Rights and Limitations of No Par Preferred Stock, Series 2000-A of the Registrant (filed as an exhibit to the Registrant's Form 8-K filed on December 26, 2000).
4.1*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Power, Inc. dated as of September 1, 1999 (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
4.2	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share.
10.1*	Agreement for Transmission Service and the Common Use of Transmission Systems dated January 1, 1986, among Black Hills Power, Inc., Basin Electric Power Cooperative, Rushmore Electric Power Cooperative, Inc., Tri-County Electric Association, Inc., Black Hills Electric Cooperative, Inc. and Butte Electric Cooperative, Inc. (filed as Exhibit 10(d) to the Registrant's Form 10-K for 1987).
10.2*	Restated and Amended Coal Supply Agreement for NS #2 dated February 12, 1993 (filed as Exhibit 10(c) to the Registrant's Form 10-K for 1992).
10.3*	Coal Leases between Wyodak Resources Development Corp. and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.4*	Further Restated and Amended Coal Supply Agreement dated May 5, 1987 between Wyodak Resources Development Corp. and Pacific Power & Light Company (filed as Exhibit 10(k) to the Registrant's Form 10-K for 1987).
10.5*	Second Restated and Amended Power Sales Agreement dated September 29, 1997, between PacifiCorp and Black Hills Power, Inc. (filed as Exhibit 10(e) to the Registrant's Form 10-K for 1997).
10.6*	Coal Supply Agreement for Wyodak Unit #2 dated February 3, 1983, and Ancillary Agreement dated February 3, 1982, between Wyodak Resources Development Corp., Pacific Power & Light Company and Black Hills Power, Inc. (filed as Exhibit 10(o) to the Registrant's Form 10-K for 1983). Amendment to Agreement for Coal Supply for Wyodak #2 dated May 5, 1987 (filed as Exhibit 10(o) to the Registrant's Form 10-K for 1987).
10.7*	Reserve Capacity Integration Agreement dated May 5, 1987, between Pacific Power & Light Company and Black Hills Power, Inc. (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1987).
10.8*	Marketing, Capacity and Storage Service Agreement between Black Hills Power, Inc. and PacifiCorp dated September 1, 1995 (filed as Exhibit 10(ag) to the Registrant's Form 10-K for 1995).
10.9*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between Wyodak Resources Development Corp. and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
10.10*	Rate Freeze Extension (filed as Exhibit 10(t) to the Registrant's Form 10-K for 1999).
10.11 +	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated January 6, 2000.
10.12 +	First Amendment to the Pension Equalization Plan of Black Hills Corporation dated January 30, 2001.
10.13 +	Black Hills Corporation Nonqualified Deferred Compensation Plan dated June 1, 1999.
10.14 +	Black Hills Corporation 1999 Stock Option Plan.
10.15*+	Agreement for Supplemental Pension Benefit for Everett E. Hoyt dated January 20, 1992 (flied as Exhibit 10(gg)

	to the Registrant's Form 10-K for 1992).
10.16*+	Change in Control Agreements for various officers (filed as Exhibit 10(af) to the Registrant's Form 10-K for 1995).
10.17*+	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1997).
10.18*+	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registration's Form 10-K for 1997).
10.19*+	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1999).
10.20*	Agreement and Plan of Merger, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 2 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.21*	Addendum to the Agreement and Plan of Merger, dated as of April 6, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 3 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.22*	Supplemental Agreement Regarding Contingent Merger Consideration, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 4 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.23*	Supplemental Agreement Regarding Restructuring of Certain Qualifying Facilities (Exhibit 5 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.24*	Addendum to the Agreement and Plan of Merger, dated as of June 30, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 6 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.25*	Registration Rights Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 7 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
10.26*	Shareholders Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 8 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital,consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. dated July 7, 2000).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Public Accountants.
23.2	Consent of Petroleum Engineer and Geologist.

- ----------

* Previously filed as part of the filing indicated and incorporated by reference herein.

\+ Indicates a board of director or management compensatory plan.

Exhibit 4.2

Number
NY ____   Shares ___

THIS CERTIFICATE IS TRANSFERABLE IN
NEW YORK, N.Y. OR MINNEAPOLIS, MN.

SEE REVERSE FOR
CERTAIN DEFINITIONS

COMMON STOCK

BLACK HILLS CORPORATION

CUSIP 092113 10 9

(Incorporated Under the Laws of the State of South Dakota)

This certifies that __________________ is the owner of _________fully paid and non-assessable shares, having a par value of $1 per share, of the common stock of Black Hills Corporation (hereinafter called the Corporation), transferable on the books of the Corporation by the holder hereof in person or by a duly authorized attorney upon surrender of this certificate properly endorsed. This certificate and the shares represented hereby are issued and shall be held subject to all the provisions of the Articles of Incorporation of the Corporation and all amendments thereof, copies of which are on file with the Transfer Agent, to all of which the holder, by acceptance hereof, assents. This certificate is not valid until countersigned by the Transfer Agent and registered by the Registrar.

WITNESS, the facsimile seal of the Corporation, and the signatures of its duly authorized officers.

Dated _______________________________

Chairman and CEO

Vice President-Controller and Corporate Secretary

Countersigned and Registered:

By ____
Transfer Agent and Registrar
Authorized Signature

BLACK HILLS CORPORATION

Notice: The Corporation will furnish to any shareholder upon request and without charge, a full statement of the designations, preferences, limitations, and relative rights of the shares of each class of stock authorized to be issued, and a like full statement relative to any preferred or special class of stock in series which the Corporation is or may be authorized to issue, or has issued, as to the variations in the relative rights and preferences between the shares of each such series so far as the same have been fixed and determined and the authority of the Board of Directors to fix and determine the relative rights and preferences of subsequent series.

The following abbreviations, when used in the inscription on the face of this certificate, shall be construed as though they were written out in full according to applicable laws or regulations:

```
TEN COM - as tenants in common UNIF GIFT MIN ACT- _____as  Custodian for _______
                                                   (Cust)                 (Minor)
                                                    under Uniform Gifts to Minors
                                                      Act______________________
                                                              (State)
UNIF TRAN MIN ACT - _____ as  Custodian  for  ______
                   (Cust)                    (Minor)
                    under Uniform Transfers to Minors
                        Act _______________________
                                 (State)
```

TEN ENT - as tenants by the entireties
JT TEN - as joint tenants with right of survivorship
and not as tenants in common
TOD - transfer on death direction in event of owner's death,
to person named on face

Additional abbreviations may also be used though not in the above list.

For Value Received, ______________________ hereby sell, assign and transfer unto ____________________________Shares of the Stock represented by the within certificate and do hereby irrevocably constitute and appoint ________________________ attorney, to transfer the same on the books of the within-named Corporation, with full power of substitution in the premises.

Dated__________________________

X__________________________________

NOTICE: THE SIGNATURE(S) TO THIS ASSIGNMENT
MUST CORRESPOND WITH THE NAME(S) AS WRITTEN
UPON THE FACE OF THE CERTIFICATE IN EVERY
PARTICULAR, WITHOUT ALTERATION OR ENLARGEMENT

OR ANY CHANGE WHATEVER.

X____________________________________

Signature Guaranteed by X____________________________________

Exhibit 10.11

PENSION EQUALIZATION PLAN
OF BLACK HILLS CORPORATION

This Pension Equalization Plan ("Plan") is hereby amended and restated by Black Hills Corporation ("Company") effective the 6th day of January, 2000.

1. PURPOSE OF PLAN.

The purpose of the Plan is to provide to a select group of management or highly compensated employees with certain retirement and death benefits in addition to those benefits which the Participants may enjoy from the Company's tax qualified defined benefit plan in order to equalize total retirement benefits being paid to persons holding like executive positions by other companies. The Plan is designed to aid the Company in attracting and retaining its executive employees, persons whose abilities, experience and judgment can contribute to the well-being of the Company. It is the intention of Company that this Plan shall be administered as an unfunded benefit plan established and maintained for a select group of management or highly compensated employees.

2. DEFINITIONS.

"Annual Compensation Limitation" shall mean the limitation on annual compensation for tax qualified retirement plans as set forth in Internal Revenue Code Section 401(a)(17) as the same may be amended hereafter from time to time.

"Average Earnings" shall mean whichever of the following results in the highest annual average Earnings: (i) a Participant's average Earnings for the five (5) consecutive full calendar years of employment during the ten (10) full calendar years of employment immediately preceding the Calculation Date, which results in the highest such average; or (ii) a Participant's average Earnings determined by dividing the sum of the following by five (5): (a) the Participant's Earnings for the four full calendar years preceding the year containing his Calculation Date; (b) the Participant's Earnings for the year containing his Calculation Date as of the Calculation Date; and (c) a portion of the Participant's Earnings for the fifth full calendar year preceding the year containing his Calculation Date determined by multiplying his Earnings for said fifth preceding full calendar year by a ratio, the numerator of which shall be 365 minus the number of days in the year containing his Calculation Date measured from the first day of said year to his Calculation Date, and the denominator of which ratio shall be 365. If the Participant has less than five (5) full calendar years of employment, the average shall be taken over his total full calendar years of employment.

"Calculation Date" shall mean the earlier of (i) the date the Participant's employment with the Company was terminated, (ii) the date that the Participant's participation in the Plan was terminated, or (iii) the date of the Participant's death.

"Committee" shall mean the Compensation Committee of the Board of Directors of the Company.

"Earnings" shall mean the compensation paid to a Participant by the Company during a calendar year, including any amounts paid to the Participant as overtime, bonus, commission or incentive compensation, any Earnings reduction under a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code, any salary reduction under a flexible benefit program under Section 125 of the Internal Revenue Code, and the amount of any salary or bonus deferred by a Participant under the Company's Nonqualified Deferred Compensation Plan, but excluding reimbursements and expenses allowances, fringe benefits, moving expenses, nonqualified deferred compensation payments, and welfare benefits.

"Pension Restoration Benefit" shall mean the benefit payable under paragraph 8.

"PEP Benefits" shall mean the benefits payable under paragraph 4.

"Salary Level" shall mean the base compensation paid to a Participant by the Company during a calendar year, including any compensation reduction under a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code or under a flexible benefit program under Section 125 of the Internal Revenue Code and any salary deferrals made by a Participant under the Company's Nonqualified Deferred Compensation Plan, but not including any amounts paid to the Participant as overtime, bonus, commission or incentive compensation, nor reimbursements and expense allowances, fringe benefits, moving expenses, nonqualified deferred compensation payments, or welfare benefits.

"Social Security Wage Base" shall mean the contribution base as determined under Section 1402(k)(1) of the Internal Revenue Code.

3. PARTICIPANTS.

Those persons eligible for participation in the Plan ("Participants") are those management employees of the Company whose Salary Level equals or exceeds the Social Security Wage Base and who are designated by the Board of Directors of the Company upon recommendation of the Chief Executive Officer of the Company. The Board of Directors may in its discretion discontinue the participation of any Participant in the Plan at any time.

4. PEP BENEFITS.

Benefits payable to Participants ("PEP Benefits") shall consist of 180 equal monthly payments, each payment in the amount of one-twelfth of the product of (i) the Participant's Average Earnings as of the Calculation Date times (ii)(a) 25 percent if the Participant's Average Earnings as of the Calculation Date is less than twice the Social Security Wage Base; or (b) 30 percent if the Participant's Average Earnings equals or exceeds twice the Social Security Wage Base; times (iii) the applicable vesting percentages provided in paragraph 7.

5. COMMENCEMENT OF PAYMENT OF PEP BENEFITS.

PEP Benefit payments shall be paid commencing at the earliest of (i) the time the Participant is 62 years of age or more and is no longer an employee of the Company; or (ii) upon the death of the Participant. PEP Benefits shall be paid to the Participant or, if deceased, to the Participant's designated beneficiary, or, if none, to his or her estate. If the Participant's death occurs after commencement of PEP Benefit payments to the Participant under the Plan, the Participant's designated beneficiary or estate will continue to receive the balance of the payments due the Participant under the Plan.

6. DESIGNATION OF BENEFICIARY.

A Participant may designate a beneficiary or beneficiaries for PEP Benefits which shall be effective upon filing written notice with the Compensation Committee of the Company on the form provided for that purpose. If more than one beneficiary designation has been filed, the beneficiary or beneficiaries designated in the notice bearing the most recent date will be deemed the valid beneficiary or beneficiaries.

7. VESTING OF PEP BENEFITS.

PEP Benefits payable under the Plan will vest at the following rate:

Years of Plan Participation	Percent of Benefit Vested
Less than 3 years	0
3 years but less than 4	20
4 years but less than 5	35
5 years but less than 6	50
6 years but less than 7	65
7 years but less than 8	80
8 or more years	100

No credit for service with the Company prior to the effective date of the Plan shall be given. The provisions for vesting set forth in this paragraph are not intended to give any Participants any rights or claim to any specific assets of the Company.

8. PENSION RESTORATION BENEFITS.

In the event that at the time of a Participant's retirement from the Company the Participant's salary level exceeds the Annual Compensation Limitation, then, the Participant shall receive an additional benefit ("Pension Restoration Benefit") which shall be measured by the difference between the monthly benefit which would have been provided to the Participant under the Company's tax qualified defined benefit plan ("Pension Plan") as if there were no Annual Compensation Limitation and the monthly benefit to be provided to the Participant under the Pension Plan. The Pension Restoration Benefit shall be determined using the same factors, actuarial or otherwise, as used in determining the Participant's Pension Plan benefit and shall be payable at like times and manner as the Pension Plan benefit.

In addition to the above benefit, in the event that any Participant's deferral of salaries or bonus under the Company's Nonqualified Deferred Compensation Plan results in a reduction of that Participant's benefits payable under the Company's Pension Plan, then the Participant shall be entitled to payment of an additional Pension Restoration Benefit which shall be a monthly benefit which shall consist of the difference between (i) the monthly benefit which would have been provided to the Participant under the Pension Plan as if the Participant had made no deferrals under the Company's Nonqualified Deferred Compensation Plan and (ii) the monthly benefit to be provided to the Participant under the Pension Plan, said benefit to be determined using the same factors, actuarial or otherwise, as used in determining the Participant's Pension Plan benefit and to be payable at like times and manner as the Pension Plan benefit.

9. LOSS OF BENEFITS.

Notwithstanding any other provisions in this Plan, if a Participant is terminated on account of misconduct or dishonesty, the Participant shall forfeit all right to any benefits payable under this Plan, including vested accrued benefits.

10. FUNDING OF PLAN.

All benefit payments under the Plan will be made from the general assets of the Company. Participants and their beneficiaries who are entitled to be paid benefits under this Plan are unsecured general creditors of the Company. The Company may, but shall not be required to, invest corporate assets in life insurance or annuity contracts to assure that the Company will have a source of funds for the payment of benefits required to be paid under this Plan. Any such insurance or annuity contract shall constitute assets of the Company and the employee shall have no right, title or interest in any such insurance or annuity contract. The Company reserves the right to refuse participation in the plan to any Participant who, if requested to do so, declines to supply information or to otherwise cooperate as necessary to allow the Company to obtain insurance on the Participant's life.

11. PLAN MAY BE MODIFIED OR DISCONTINUED.

The Company reserves the right to amend, modify or discontinue the Plan at any time. Any modification or discontinuance of benefits shall not reduce accrued benefits which become vested prior thereto.

12. WITHHOLDING.

There shall be deducted from all benefits paid under this Plan the amount of any taxes required to be withheld by any federal, state or local government. The Participants and their beneficiaries, distributees and personal representatives will bear any and all federal, foreign, state, local or other income or other taxes imposed on amounts paid under this Plan.

13. ASSIGNABILITY.

No right to receive payments under this Plan shall be subject to voluntary or involuntary alienation, assignment or transfer.

14. ADMINISTRATION OF THE PLAN.

The Plan shall be administered by the Committee. The Committee shall conclusively interpret the provisions of the Plan, decide all claims, and shall make all determinations under the Plan. The Committee shall act by vote or written consent of a majority of its members.

15. CLAIMS PROCEDURE.

All claims for benefits under the Plan shall be made to the Committee. If the Committee denies a claim, the Committee may provide notice to the Participant or beneficiary, in writing, within 90 days after the claim is filed unless special circumstances require an extension of time for processing the claim, not to exceed an additional 90 days. If the Committee does not notify the Participant or beneficiary of the denial of the claim within the time period specified above, then the claim shall be deemed denied. The notice of a denial of a claim shall be written in a manner calculated to be understood by the claimant and shall set forth (1) specific references to the pertinent Plan provisions on which the denial is based; (2) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation as to why such information is necessary; and (3) an explanation of the Plan's claim procedure.

Within 60 days after receipt of the above material, the claimant shall have a reasonable opportunity to appeal the claim denial to the Committee for a full and fair review. The claimant or his duly authorized representative may (1) request a review upon written notice to the Committee; (2) review pertinent documents; and (3) submit issues and comments in writing.

A decision on the review by the Committee will be made not later than 60 days after receipt of a request for review, unless special circumstances require an extension of time for processing (such as the need to hold a hearing), in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. The decision on review shall be in writing and shall include specific reasons for the decision, written in a manner calculated to be understood by the claimant, as well as specific references to the pertinent Plan provisions on which the decision is based.

16. GOVERNING LAW.

This agreement shall be governed by and construed in accordance with the laws of the state of South Dakota.

17. NO EMPLOYMENT CONTRACT.

Neither the action taken by the Company in establishing the Plan or any action taken by it or by the Committee under the provisions hereof or any provision of the Plan shall be construed as giving to any eligible Participant the right to be retained in the employment of the Company.

18. NONQUALIFIED PLAN.

This Plan is not intended to be a tax qualified plan under the Internal Revenue Code.

BLACK HILLS CORPORATION

By /s/ Daniel P. Landguth
Its Chairman and CEO

Exhibit 10.12

FIRST AMENDMENT TO THE PENSION EQUALIZATION PLAN OF BLACK HILLS CORPORATION

The Pension Equalization Plan of Black Hills Corporation is hereby amended effective the 30th day of January, 2001.

1. Add to paragraph 2, Definitions, the following definition:

   "Section 415 Benefit Limitation" shall mean the limitation on the provision of annual benefits with respect to defined benefit plans as set forth in Internal Revenue Code Section 415(b) as the same may be amended hereafter from time to time.

2. Paragraph 8, Pension Restoration Benefits of the Plan, shall be amended to read as follows:

   In the event that a Participant's benefit under the Company's tax qualified defined benefit plan ("Pension Plan") is reduced, or is required to be reduced, because of (i) the Annual Compensation Limitation; (ii) the Section 415 Benefit Limitation; or (iii) the Participant's deferral of salaries or bonus under the Company's Nonqualified Deferred Compensation Plan, then, the Participant shall be entitled to receive an additional benefit ("Pension Restoration Benefit"), which shall be measured by the difference between (x) the monthly benefit which would have been provided to the Participant under the Pension Plan without regard to the reduction in the Pension Plan benefit caused by any of the foregoing limitations in (i), (ii), or (iii) above, and (y) the monthly benefit to be provided to the Participant under the Pension Plan. The Pension Restoration Benefit shall be determined using the same factors, actuarial or otherwise, as used in determining the Participant's Pension Plan benefit and shall be payable at like times and manner as the Pension Plan benefit.

BLACK HILLS CORPORATION

By /s/ Daniel P. Landguth
Its Chairman & CEO

Exhibit 10.13

BLACK HILLS CORPORATION
NONQUALIFIED DEFERRED COMPENSATION PLAN

1. Purpose of Plan and Effective Date. The effective date of this Black Hills Corporation Nonqualified Deferred Compensation Plan ("Plan") shall be the 1st day of June, 1999. The purpose of the Plan is to provide benefits to a select group of management or highly compensated employees who contribute materially to the continued growth, development and future business success of the Company. It is the intention of Company that this Plan shall be administered as an unfunded benefit plan established and maintained for a select group of management or highly compensated employees.

2. Definitions. For purposes of this Plan, the following phrases or terms have the indicated meanings unless otherwise clearly apparent from the context:

(a) "Beneficiary" shall mean the person, persons, or estate of a Participant, entitled to receive any benefits subsequent to the death of a Participant under a Beneficiary Designation form entered into in accordance with the terms of this Plan.

(b) "Base Salary" shall mean the compensation paid to a Participant by the Employer during a calendar year, including any compensation reduction under a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code or under a flexible benefit program under Section 125 of the Internal Revenue Code but not including any amounts paid to the Participant as overtime, bonus, commission, or incentive compensation, nor reimbursements and expense allowances, fringe benefits, moving expenses, nonqualified deferred compensation, or welfare benefits.

(c) "Beneficiary Designation" shall mean the form of written agreement, by which the Participant names the Beneficiary(ies) under the Plan.

(d) "Board of Directors" shall mean the Board of Directors of Company.

(e) "Change in Control" shall mean any of the following events:

(1) An acquisition (other than directly from the Company) of any common stock of the Company (the "Common Stock") by any "Person" (as the term person is used for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), immediately after which such Person has "Beneficial Ownership" (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of thirty percent (30%) or more of the Common Stock of the Company; provided, however, in determining whether a Change in Control has occurred, Common Stock which is acquired in a "Noncontrol Acquisition" (as hereinafter defined) shall not constitute an acquisition which would cause a Change in Control. A "Noncontrol Acquisition" shall mean an acquisition by (i) an employee benefit plan (or a trust forming a part thereof) maintained by (A) the Company or (B) any corporation or other Person of which a majority of its voting power or its voting equity securities ("Voting Securities") or equity interest is owned, directly or indirectly, by the Company (for purposes of this definition, a "Subsidiary"), (ii) the Company or its Subsidiaries, or (iii) any Person in connection with a "Noncontrol Transaction" (as hereinafter defined);

(2) The individuals who, as of January 1, 1997, are members of the Board (the "Incumbent Board"), cease for any reason to constitute at least two-thirds of the members of the Board; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened "Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies

or consents by or on behalf of a Person other than the Board (a "Proxy Contest") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest; or

(3) Approval by shareholders of the Company of:

(i) A merger, consolidation or reorganization involving the Company, unless such merger, consolidation or reorganization is a "Noncontrol Transaction." A "Noncontrol Transaction" shall mean a merger, consolidation or reorganization of the Company where:

(A) the shareholders of the Company, immediately before such merger, consolidation or reorganization, own directly or indirectly immediately following such merger, consolidation or reorganization, at least seventy percent (70%) of the combined voting power of the outstanding Voting Securities of the corporation resulting from such merger or consolidation or reorganization (the "Surviving Corporation") in substantially the same proportion as their ownership of the Voting Securities immediately before such merger, consolidation or reorganization.

(B) the individuals who were members of the Incumbent Board immediately prior to the execution of the agreement providing for such merger, consolidation or reorganization constitute at least two-thirds of the members of the board of directors of the Surviving Corporation, or a corporation beneficially directly or indirectly owning a majority of the Voting Securities of the Surviving Corporation, and

(C) no Person other than (i) the Company, (ii) any Subsidiary, (iii) any employee benefit plan (or any trust forming a part thereof) maintained by the Company, the Surviving Corporation, or any Subsidiary, or (iv) any Person who, immediately prior to such merger, consolidation or reorganization had Beneficial Ownership of thirty percent (30%) or more of the then outstanding Voting Securities), has Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the Surviving Corporation's then outstanding Voting Securities.

(ii) A complete liquidation or dissolution of the Company; or

(iii) An agreement for the sale or other disposition of all or substantially all of the assets of the Company to any Person other than (x) a transfer to a Subsidiary or (y) a sale or transfer of a Subsidiary by the Company except if such sale or transfer would be a sale or other disposition of all or substantially all of the assets of the Company.

(4) Notwithstanding the foregoing, (i) a Change in Control shall not be deemed to occur solely because any Person (the "Subject Person") acquired Beneficial Ownership of more than the permitted amount of the then outstanding Common Stock as a result of the acquisition of Common Stock by the Company which, by reducing the number of shares of Common Stock then outstanding, increases the proportional number of shares Beneficially Owned by the Subject Persons, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of Common Stock by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional Common Stock which increases the percentage of the then outstanding Common Stock Beneficially Owned by the Subject Person, then a Change in Control shall occur; and (ii) a Change in Control shall not be deemed to occur unless and until all regulatory approvals required to effect a Change in Control of the Company have been obtained.

(f) "Committee" shall mean the Compensation Committee of the Board of Directors.

(g) "Company" shall mean Black Hills Corporation, a South Dakota corporation, with principal offices in the State of South Dakota.

(h) "Elective Contribution" means that part of a Participant's compensation that such Participant has elected to defer pursuant to Section 4.1.

(i) "Incentive Contribution" means that portion of a Participant's award under the Company's Short Term Annual Incentive Plan ("STIP") which the Participant has elected to defer under the STIP and under Section 4.2.

(j) "Employer" shall mean the Company and any Subsidiary that duly adopts the Plan.

(k) "Employee" shall mean any person who is in the regular full-time employment of the Company or a Subsidiary, as determined by the personnel rules and practices of the Company or a Subsidiary. The term does not include persons who are retained by the Company or a Subsidiary solely as consultants.

(l) "Participant" shall mean an Employee who is selected to participate in the Plan.

(m) "Participant's Account" shall mean the memorandum account established and maintained by the Company for each Participant with respect to the Participant's total interest in the Plan resulting from the Participant's Elective Contributions and Incentive Contributions plus the earnings thereon.

(n) "Plan Year" shall mean the Plan's accounting year of 12 months beginning on January 1 and ending on the following December 31.

(o) "Retirement" and "Retire" shall mean severance of employment with Employer, for any reason.

(p) "Subsidiary" shall mean any business organization in which Company, directly or indirectly, owns a majority of its voting power or voting equity securities or equity interest and which the Board of Directors designates as a Subsidiary for purposes of this Plan.

3. Eligibility and Participation. In order to be eligible for participation in the Plan, an Employee must be selected by the Committee. The Committee, in its sole and absolute discretion, shall determine eligibility for participation from among management or highly compensated employees of the Employer in accordance with the purposes of the Plan.

4. Contributions.

4.1 Elective Contributions. Each Participant may elect to defer up to 50% of the Participant's Base Salary. An election to defer must be made in writing prior to the beginning of a Plan Year; provided, that (a) in the Plan Year in which the Plan is first implemented, a Participant may make an election to defer compensation earned subsequent to the election within 30 days after the date the Plan is effective and (b) in the first year in which a Participant becomes eligible to participate in the Plan, the newly eligible Participant may make an election to defer compensation earned subsequent to the election within 30 days after the date the Participant becomes eligible. This election shall be irrevocable for that Plan Year and shall continue to be valid unless subsequently revoked for the following Plan Years. The amount by which the Participant's Base Salary is reduced shall be that Participant's Elective Contribution and shall be allocated to that Participant's Account on a monthly basis.

4.2 Incentive Contributions. In addition to the Elective Contributions, a Participant, if eligible under the STIP, may elect under the terms of the Company's STIP, to defer the receipt of all or any portion of a Participant's award thereunder, including shares of Company stock. The amount of the award deferred under the STIP shall be allocated to a Participant's Account. In the event that Participant defers a stock award under the STIP, then the Company shall establish within the Participant's Account a common stock equivalent memorandum account ("Stock Account") and shall credit the Stock Account with Company common stock equivalents, including fractional equivalents. Appropriate adjustments shall be made to the Stock Account for stock splits, stock dividends, mergers, consolidation and other similar circumstances affecting the Company common stock.

5. Earnings on Participant's Account. Each Participant may, at the time of his deferral election, choose to allocate the amount of Elective Contributions deferred and the amount of the Incentive Contributions deferred (except for the Company stock deferred) into certain categories of hypothetical investments to be determined by the Participant as are available under the range of investments as may be allowed by any third-party service provider to the Plan, or trustee, if any, or if none, from the range of investments as determined by the Committee in its discretion. The amounts deferred into a Participant's Account shall change in value based upon the allocated underlying hypothetical investments, including Company Stock.

6. Payment of Benefit. Upon Retirement of a Participant, the Employer shall pay to or cause to be paid to such Participant the then amount in the Participant's Account. At the time that a Participant makes a deferral election, the Participant shall choose from the following payment options: (a) a lump sum payment to be paid within 30 days of Retirement, or (b) annual or monthly installment payments over a period of years designated by Employee but not to exceed 15 years. Once payments hereunder have begun, the payment option chosen is irrevocable. In the event that a Participant has elected a payment option and desires to change the same prior to such payment option becoming irrevocable, Participant may make a request of the Committee to change the payment option; provided, that such request shall not become effective until the Plan Year subsequent to the Plan Year in which the request is made.

If the installment payment is elected, the first payment shall be made in cash to Employee on the 1st day of January following the date on which Employee Retires. Annual payments for each succeeding year shall be paid to Employee on the first January of each succeeding year. Monthly payments shall be made on the first day of each month. Subsequent to the first installment payment, accrued interest on the unpaid accumulated balance will be added to each subsequent payment based on amortization over the term of payment. The interest rate to be used shall be equal to the seven year United States Treasury Bond yield as determined on the Retirement date.

In the event of Employee's death after Retirement, and in the event installment payments had been elected, the payments shall be made as provided herein on each payment date established and shall continue until paid in full to Participant's Beneficiary; provided, however, that Participant's Beneficiary, or personal representative, as the case may be, shall have the option, by written notice given to Company within 12 months after Participant's death, to receive any remaining installment payments in a lump sum. If such option is exercised, the lump sum shall be paid within 60 days thereafter.

7. Payment of Benefits upon Unforeseeable Emergency. Notwithstanding paragraph 6 above, in the event of an Unforeseeable Emergency as hereafter defined, a Participant may withdraw amounts from the Participant's Account to the extent reasonably needed to satisfy the Unforeseeable Emergency. In addition, in the event of an Unforeseeable Emergency, Participant may cease contributions during a Plan Year notwithstanding Section 4.1. For the purposes of this paragraph an "Unforeseeable Emergency" is a severe financial hardship to the Participant resulting from a sudden and unexpected illness or accident of the Participant or a dependent (as defined in Internal Revenue Code ss. 152(a)) of the Participant, loss of the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. The circumstances that will constitute an Unforeseeable Emergency will depend upon the facts of each case, but, in any case, payment may not be made to the extent that such hardship is or may be relieved--(a) through reimbursement or compensation by insurance or otherwise; (b) by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship; or (c) by cessation of Contributions under the Plan. Examples of what are not considered to be an Unforeseeable Emergency include the need to send a Participant's child to college or the desire to purchase a home.

8. Death Benefit and Disability Benefits.

8.1 Amount and Payment of Death Benefit. If a Participant dies before Retirement, the Employer will pay or cause to be paid as a death benefit to such Participant's Beneficiary the balance of the Participant's Account, in a lump sum.

Proof of death in a form determined acceptable by the Committee must be furnished.

8.2 Total Disability. If a Participant becomes totally and permanently disabled before he or she ceases to be employed by the Employer, the balance of the Participant's Account shall be paid in a lump sum; provided, that the Committee, in its sole discretion, may pay out Participant's Account balance in installments.

The determination of total and permanent disability for purposes of this section, shall be made by the Committee in its sole and absolute discretion.

8.3 Time of Payment. The benefit paid under Section 8.1 or Section 8.2 shall be paid as soon as possible following the Participant's death or the date on which the Committee determines a Participant is totally or permanently disabled but not later than 12 months following Participant's death or determination of total or permanent disability.

9. Change in Control. In the event of a Change in Control, a Participant shall have the option to request immediate distribution of the Participant's Account as if Participant had Retired, whether or not Participant's employment status with Company or any successor of Company has changed.

10. Beneficiary. Participant shall designate a Beneficiary or Beneficiaries to receive benefits under the Plan by completing the Beneficiary Designation. If more than one Beneficiary is named, the shares or precedence of each Beneficiary shall be indicated. A Participant shall have the right to change the Beneficiary by submitting to the Committee a new Beneficiary Designation. The Beneficiary Designation must be approved in writing by the Committee; however, upon the Committee's acknowledgment of approval, the effective date of the Beneficiary Designation shall be the date it was executed by the Participant. If the Committee has any doubt as to the proper Beneficiary to receive payments, it shall have the right to withhold payments until the matter is finally adjudicated or to interplead the Participant's Account into a court of competent jurisdiction. Any payment made by the Employer in good faith and in accordance with the provisions of this Plan and a Participant's Beneficiary Designation shall fully discharge the Employer and Committee from all further obligations with respect to the payment.

11. Source of Benefits.

11.1 Benefits Payable from General Assets. Amounts payable shall be paid exclusively from the general assets of the Employer, and no person entitled to payment shall have any claim, right, security interest, or other interest in any fund, trust, account, or other asset of the Employer that may be looked to for payment. The Employer's liability for the payment of benefits shall be evidenced only by this Plan. In all events, it is the intent of the Employer that the Plan be treated as unfunded for tax purposes and for purposes of Title I of ERISA.

11.2 Investments to Facilitate Payment of Benefits. Although the Employer is not obligated to invest in any specific asset or fund in order to provide the means for the payment of any liabilities under this Plan, the Employer may elect to do so and may also elect to acquire life insurance policies on any Participant or create a "Rabbi" trust.

The Participant also understands and agrees that the participation of Participant, in any way, in the acquisition of any insurance policy or any other general asset by the Employer shall not constitute a representation to the Employee, the designated recipient, or any person claiming through the Employee that any of them has a special or beneficial interest in the general asset.

11.3 Employer Obligation. The Employer shall have no obligation of any nature whatsoever to a Participant under this Plan other than what is specifically stated in the Plan.

12. Termination of Employment. This Plan does not obligate the Employer to continue the employment of a Participant with the Employer nor does it limit the right of the Employer at any time and for any reason to terminate the Participant's employment. Termination of a Participant's employment with the Employer for any reason, whether by action of the Employer or otherwise, shall immediately terminate a Participant's continued participation in this Plan. In no event shall this Plan by its terms or implications constitute an employment contract of any nature whatsoever between the Employer and a Participant.

13. Terminations, Amendments, Modification or Supplement of Plan.

13.1 Termination, Amendment and Modifications. The Employer reserves the right to terminate, amend, modify or supplement this Plan, wholly or partially, and from time to time, at any time. Such right to terminate, amend, modify, or supplement this Plan shall be exercised for the Employer by the Board of Directors; provided, however, that no action to terminate this Plan shall be taken except upon written notice to each Participant to be affected, which notice shall be given not less than 30 days prior to the action. Any action under this Section 14.1 shall not affect rights previously accrued under this Plan.

13.2 Rights and Obligations Upon Termination. Upon the termination of this Plan by the Board of Directors, the Participant's Account shall be paid as if the Participant had Retired as of the date the Plan was terminated.

14. Other Benefits and Agreements. The benefits provided for a Participant and any Beneficiary hereunder and under this Plan are in addition to any other benefits available to such Participant under any other program or plan of the Employer for its employees, and, except as may otherwise be expressly provided for, this Plan shall supplement and shall not supersede, modify, or amend any other program or plan of the Employer or a Participant.

15. Restrictions on Alienation of Benefits. No right or benefit under this Plan shall be subject to sale, assignment, or encumbrances, and any attempt to sell, assign, or encumber the Plan shall be void. No right or benefit hereunder shall in any manner be liable for or subject to the debts, contract, liabilities, or torts of the person entitled to such benefit. If any Participant or Beneficiary under this Plan should become bankrupt or attempt to sell, assign, or encumber any right to a benefit under this Plan then such right or benefit shall, in the discretion of the Committee, terminate, and, in that event, the Committee shall hold or apply the same or any part of it for the

benefit of the Participant or Beneficiary, or the Participant's spouse, children, or other dependents, in a manner and in a portion that the Committee, in its sole and absolute discretion, may deem proper.

16. Withholding. There shall be deducted from all benefits paid under this Plan the amount of any taxes required to be withheld by any federal, state or local government. The Participants and their Beneficiaries will bear any and all federal, foreign, state, local or other income or other taxes imposed on amounts paid under this Plan.

17. Administration of this Plan.

17.1 Appointment of Committee. The general administration of this Plan, as well as its construction and interpretation, shall be vested in the Committee or its successor, as the members of which are designated and appointed from time to time by the Board of Directors.

17.2 Committee Rules and Powers -- General. Subject to the provisions of this Plan, the Committee shall from time to time establish rules, forms, and procedures for the administration of this Plan. Such decisions, actions and records of the Committee shall be conclusive and binding upon the Employer and all persons having or claiming to have any right or interest in or under the Plan.

17.3 Reliance on Certificate, Etc. The members of the Committee and the officers and directors of the Employer shall be entitled to rely on all certificates and reports made by any duly appointed accountants, and on all opinions given by any duly appointed legal counsel. Such legal counsel may be counsel for the Employer.

17.4 Determination of Benefits. In addition to the powers specified, the Committee shall have the power to compute and certify under this Plan the amount and kind of benefits from time to time payable to Participants and their Beneficiaries and to authorize all disbursements for such purposes.

17.5 Information to Committee. To enable the Committee to perform its functions, the Employer shall supply full and timely information to the Committee on all matters relating to the compensation of all Participants, their retirement, death or other cause for termination of employment, and such other pertinent facts as the Committee may require.

18. Claims. All claims for benefits under the Plan shall be made to the Committee. If the Committee denies a claim, the Committee may provide notice to the Participant or beneficiary, in writing, within 90 days after the claim is filed unless special circumstances require an extension of time for processing the claim, not to exceed an additional 90 days. If the Committee does not notify the Participant or Beneficiary of the denial of the claim within the time period specified above, then the claim shall be deemed denied. The notice of a denial of a claim shall be written in a manner calculated to be understood by the claimant and shall set forth (1) specific references to the pertinent Plan provisions on which the denial is based; (2) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation as to why such information is necessary; and (3) an explanation of the Plan's claim procedure.

Within 60 days after receipt of the above material, the claimant shall have a reasonable opportunity to appeal the claim denial to the Committee for a full and fair review. The claimant or his duly authorized representative may (1) request a review upon written notice to the Committee; (2) review pertinent documents; and (3) submit issues and comments in writing.

A decision on the review by the Committee will be made not later than 60 days after receipt of a request for review, unless special circumstances require an extension of time for processing (such as the need to hold a hearing), in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. The decision on review shall be in writing and shall include specific reasons for the decision, written in a manner calculated to be understood by the claimant, as well as specific references to the pertinent Plan provisions on which the decision is based.

19. Miscellaneous.

19.1 Execution of Receipts and Releases. Any payment to any Participant, a Participant's legal representative, or Beneficiary in accordance with the provisions of this Plan shall, to the extent thereof, be in full satisfaction of all claims against the Employer. The Employer may require the Participant, legal representative, or Beneficiary, as a condition precedent to payment, to execute a receipt and release in a form it may determine.

19.2 No Guarantee of Interests. Neither the Committee nor any of its members guarantees the payment of any amounts which may be or become due to any person or entity under this Plan. The liability of the Employer to make any payment under this Plan is limited to the then available assets of the Employer.

19.3 Employer Records. Records of the Employer as to a Participant's employment, termination of employment and the reason therefor, re-employment, authorized leaves of absence, and compensation shall be conclusive on all persons and entities, unless determined to be incorrect.

19.4 Evidence. Evidence required of anyone under this Plan and any Plan Agreement executed may be by certificate, affidavit, document, or other information which the person or entity acting on it considers pertinent and reliable, and signed, made, or presented by the proper party or parties.

19.5 Administration Expenses. The Company shall bear all costs and expenses necessary to administer the Plan.

19.6 Notice. Any notice which shall or may be given under this Plan shall be in writing and shall be mailed by United States mail, postage prepaid. If notice is to be given to the Employer, such notice shall be addressed to the Employer at:

Black Hills Corporation
P. O. Box 1400
Rapid City, SD 57709

marked to the attention of the Secretary of Black Hills Corporation.

19.7 Change of Address. Any party may, from time to time, change the address to which notices shall be mailed by giving written notice of such new address.

19.8 Effect of Provisions. The provisions of this Plan shall be binding upon the Employer and its successors and assigns, and upon the Participant, Beneficiaries, assigns, heirs, executors and administrators.

19.9 Headings. The titles and headings of Articles and Sections are included for convenience of reference only and are not to be considered in the construction of the provisions hereof.

19.10 Governing Law. All questions arising with respect to this Plan shall be determined by reference to the laws of the State of South Dakota unless preempted by federal law.

BLACK HILLS CORPORATION

By: /s/ Daniel P. Landguth
Its Chairman, President & CEO

Exhibit 10.14

BLACK HILLS CORPORATION 1999
STOCK OPTION PLAN

ARTICLE 1. Establishment, Objectives, Duration

1.1 Establishment of Plan. Black Hills Corporation (hereinafter referred to as the "Company"), hereby establishes an incentive compensation plan to be known as the "Black Hills Corporation 1999 Stock Option Plan" (hereinafter referred to as the "Plan"), as set forth in this document. The Plan permits the grant of Nonqualified Stock Options and Incentive Stock Options.

Subject to approval by the Company's shareholders, the Plan shall become effective as of May 11, 1999 (the "Effective Date") and shall remain in effect as provided in Section 1.3 hereof.

1.2 Objectives of the Plan. The objectives of the Plan are to optimize the profitability and growth of the Company through incentives which are consistent with the Company's objectives and which link the interests of Participants to those of the Company's shareholders; to provide Participants with an incentive for excellence in individual performance; and to promote teamwork among Participants.

The Plan is further intended to provide flexibility to the Company in its ability to motivate, attract, and retain the services of Participants who make significant contributions to the Company's success and to allow Participants to share in the success of the Company.

1.3 Duration of the Plan. The Plan shall commence on the Effective Date, as described in Section 1.1 hereof, and shall remain in effect, subject to the right of the Board of Directors to amend or terminate the Plan at any time pursuant to Article 11 hereof, until all Shares subject to it shall have been purchased or acquired according the Plan's provisions. However, in no event may an Award be granted under the Plan on or after May 11, 2009.

ARTICLE 2. Definitions

Whenever used in the Plan, the following terms shall have the meanings set forth below, and when the meaning is intended, the initial letter of the word shall be capitalized:

2.1 "Award" means, individually or collectively, a grant under this Plan of Nonqualified Stock Options or Incentive Stock Options.

2.2 "Award Agreement" means an agreement entered into by the Company and each Participant setting forth the terms and provisions applicable to Awards granted under this Plan.

2.3 "Beneficial Owner" or "Beneficial Ownership" shall have the meaning ascribed to such term in Rule 13d-3 of the General Rules and Regulations under the Exchange Act.

2.4 "Board" or "Board of Directors" means the Board of Directors of the Company.

2.5 "Change in Control" of the Company shall be deemed to have occurred (as of a particular day, as specified by the Board) upon the occurrence of any event described in this Section 2.5 as constituting a Change in Control.

(a) An acquisition (other than directly from the Company) of any Shares of the Company by any person immediately after which such Person has Beneficial Ownership of thirty percent (30%) or more of the Shares of the Company; provided, however, in determining whether a Change in Control has occurred, Shares which are acquired in a "Non-Control Acquisition" (as hereinafter defined) shall not constitute an acquisition which would cause a Change in Control. A "Non-Control Acquisition" shall mean an acquisition by (i) an employee benefit plan (or a trust forming a part thereof) maintained by (A) the Company; or (B) a Subsidiary; (ii) the Company or its Subsidiaries; or (iii) any Person in connection with a "Non-Control Transaction" (as hereinafter defined);

(b) The individuals who, as of the Effective Date hereof, are members of the Board (the "Incumbent Board") cease for any reason to constitute at least two-thirds (2/3) of the members of the Board; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds (2/3) of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board (a "Proxy Contest") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest; or

(c) Approval by shareholders of the Company of:

(i) A merger, consolidation, or reorganization involving the Company, unless such merger, consolidation, or reorganization is a "Non-Control Transaction." A "Non-Control Transaction" shall mean a merger, consolidation, or reorganization of the Company where:

(A) the shareholders of the Company, immediately before such merger, consolidation, or reorganization, own directly or indirectly, immediately following such merger, consolidation, or reorganization, at least seventy percent (70%) of the combined voting power of the outstanding Voting Securities of the corporation resulting from such merger or consolidation or reorganization (the "Surviving Corporation") in substantially the same proportion as their ownership of the Voting Securities immediately before such merger, consolidation, or reorganization;

(B) the individuals who were members of the Incumbent Board immediately prior to the execution of the agreement providing for such merger, consolidation, or reorganization constitute at least two-thirds (2/3) of the members of the board of directors of the Surviving Corporation, or a corporation beneficially directly or indirectly owning a majority of the Voting Securities of the Surviving Corporation; and

(C) no Person other than (i) the Company; (ii) any Subsidiary; (iii) any employee benefit plan (or any trust forming a part thereof) maintained by the Company, the Surviving Corporation, or any Subsidiary; or (iv) any Person who, immediately prior to such merger, consolidation, or reorganization had Beneficial Ownership of thirty percent (30%) or more of the then outstanding Voting Securities), has Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the Surviving Corporation's then outstanding Voting Securities.

(ii) A complete liquidation or dissolution of the Company; or

(iii) An agreement for the sale of other disposition of all or substantially all of the assets of the Company to any Person other than (x) a transfer to a Subsidiary; or (y) a sale or transfer of a Subsidiary by the Company except if such sale or transfer would be a sale or other disposition of all or substantially all of the assets of the Company.

(d) Notwithstanding the foregoing, (i) a Change in Control shall not be deemed to occur solely because any Person (the "Subject Person") acquired Beneficial Ownership of more than the permitted amount of the then outstanding Common Stock as a result of the acquisition of Shares by the Company which, by reducing the number of Shares then outstanding, increases the proportional number of shares beneficially owned by the Subject Persons, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of Shares by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional Shares which increases the percentage of the then outstanding Shares beneficially owned by the Subject Person, then a Change in Control shall occur; and (ii) a Change in Control shall not be deemed to occur unless and until all regulatory approvals required to effect a Change in Control of the Company have been obtained.

2.6 "Code" means the Internal Revenue Code of 1986, as amended from time to time.

2.7 "Committee" means the Compensation Committee of the Board, as specified in Article 3 herein, or such other Committee appointed by the Board to administer the Plan with respect to grants of Awards.

2.8 "Company" means Black Hills Corporation, together with any and all Subsidiaries, and any successor thereto as provided in Article 14 herein.

2.9 "Director" means any individual who is a member of the Board of Directors of the Company.

2.10 "Disability" shall have the meaning ascribed to such term in the Participant's governing long-term disability plan.

2.11 "Effective Date" shall have the meaning ascribed to such term in Section 1.1 hereof.

2.12 "Employee" means any full-time, active employee of the Company. Directors who are not employed by the Company shall not be considered Employees under this Plan.

2.13 "Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time, or any successor act thereto.

2.14 "Fair Market Value" shall be determined on the basis of the closing sale price on the principal securities exchange on which the Shares are traded or, if there is no such sale on the relevant date, then on the last previous day on which a sale was reported.

2.15 "Incentive Stock Option" or "ISO" means an option to purchase Shares granted under Article 6 herein and which is designated as an Incentive Stock Option and which is intended to meet the requirements of Code Section 422.

2.16 "Insider" shall mean an individual who is, on the relevant date, an officer, director or ten percent (10%) beneficial owner of any class of the Company's equity securities that is registered to Section 12 of the Exchange Act, all as defined under Section 16 of the Exchange Act.

2.17 "Nonemployee Director" means an individual who is a member of the Board of Directors of the Company but who is not an Employee of the Company.

2.18 "Nonqualified Stock Option" or "NQSO" means an option to purchase Shares granted under Article 6 herein and which is not intended to meet the requirements of Code Section 422.

2.19 "Option" means an Incentive Stock Option or a Nonqualified Stock Option, as described in Article 6 herein.

2.20 "Option Price" means the price at which a Share may be purchased by a Participant pursuant to an Option.

2.21 "Participant" means an Employee who has outstanding an Award granted under the Plan. The term "Participant" shall not include Nonemployee Directors.

2.22 "Person" shall have the meaning ascribed to such term in Section 3(a)(9) of the Exchange Act and used in Sections 13(d) and 14(d) thereof, including a "group" as defined in Section 13(d) thereof.

2.23 "Retirement" shall have the meaning ascribed to such term in the Company's tax-qualified defined benefit retirement plan.

2.24 "Shares" means the shares of Common Stock of the Company.

2.25 "Subsidiary" means any corporation or other Person of which a majority of its voting power or its voting equity securities ("Voting Securities") or equity interest is owned, directly or indirectly, by the Company.

Article 3. Administration

3.1 The Committee. The Plan shall be administered by the Compensation Committee of the Board, or by any other Committee appointed by the Board, which Committee shall satisfy the "disinterested administration" rules of Rule 16b-3 under the Exchange Act, or any successor provision. The members of the Committee shall be appointed from time to time by, and shall serve at the discretion of, the Board of Directors.

3.2 Authority of the Committee. Subject to the provisions herein, the Committee shall have full power to select Employees who shall participate in the Plan; determine the sizes and types of Awards; determine the terms and conditions of Awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to Employees; establish, amend, or waive rules and regulations for the Plan's administration as they apply to Employees; and (subject to the provisions of Article 11 herein) amend the terms and conditions of any outstanding Award to the extent such terms and conditions are within the discretion of the Committee as provided in the Plan. Further, the Committee shall make all other determinations which may be necessary or advisable for the administration of the Plan, as the Plan applies to Employees. As permitted by law, the Committee may delegate its authority as identified herein.

3.3 Decisions Binding. All determinations and decisions made by the Committee pursuant to the provisions of the Plan and all related orders and resolutions of the Board shall be final, conclusive and binding on all persons, including the Company, its shareholders, Employees, Participants, and their estates and beneficiaries.

Article 4. Shares Subject to the Plan

4.1 Number of Shares Available for Grants. Subject to adjustment as provided in Section 4.3 herein, the number of Shares which may be issued on exercise of Options shall be 700,000. Such Shares may be authorized but unissued Shares, treasury Shares, Shares acquired on the open market specifically for distribution under this Plan, or any combination thereof, as the Committee may from time to time determine.

4.2 Lapsed Awards. If any Award granted under this Plan is canceled, terminates, expires, or lapses for any reason any Shares subject to such Award again shall be available for the grant of an Award under the Plan.

4.3 Adjustments in Authorized Shares. In the event of any change in corporate capitalization, such as a stock split, or a corporate transaction, such as any merger, consolidation, separation, including a spin-off, or other distribution of stock or property of the Company, any reorganization (whether or not such reorganization comes within the definition of such term in Code Section 368) or any partial or complete liquidation of the Company, such adjustment shall be made in the number and class of Shares which may be delivered under Section 4.1, in the number and class of and/or price of Shares subject to outstanding Awards granted under the Plan, as may be determined to be appropriate and equitable by the Committee, in its sole discretion, to prevent dilution or enlargement of rights; provided, however, that the number of Shares subject to any Award shall always be a whole number.

Article 5. Eligibility and Participation

5.1 Eligibility. Persons eligible to participate in this Plan include all Employees of the Company, including Employees who are members of the Board.

5.2 Actual Participation. Subject to the provisions of the Plan, the Committee may, from time to time, select from all eligible Employees, those to whom Awards shall be granted and shall determine the nature and amount of each Award.

Article 6. Stock Options

6.1 Grant of Options. Subject to the terms and provisions of the Plan, Options may be granted to Participants in such number, and upon such terms, and at any time and from time to time as shall be determined by the Committee.

6.2 Award Agreement. Each Option grant shall be evidenced by an Award Agreement that shall specific the Option Price, the duration of the Option, the number of Shares to which the Option pertains, and such other provisions as the Committee shall determine. The Award Agreement also shall specify whether the Option is intended to be an ISO within the meaning of Code Section 422, or an NQSO whose grant is intended not to fall under the provisions of Code Section 422.

6.3 Option Price. The Option Price for each grant of an Option under this Plan shall be at least equal to one hundred percent (100%) of the Fair Market Value of a Share on the date the Option is granted or a higher amount. No repricing of Options by any method shall be allowed, including, without limitation, cancellation and reissuance.

6.4 Duration of Options. Each Option granted to an Employee shall expire at such time as the Committee shall determine at the time of the grant; provided, however, that no Option shall be exercisable later than the tenth (10th) anniversary date of its grant.

6.5 Exercise of Options. Options granted under this Article 6 shall be exercisable at such times and be subject to such restrictions and conditions as the Committee shall in each instance approve, which need not be the same for each grant or for each Participant.

6.6 Payment. Options granted under this Article 6 shall be exercised by the delivery of a written notice of exercise to the Company, setting forth the number of Shares with respect to which the Option is to be exercised, accompanied by full payment for the Shares.

The Option Price upon exercise of any Option shall be payable to the Company in full either (a) in cash or its equivalent; (b) if permitted in the governing Award Agreement, by tendering previously acquired Shares having an aggregate Fair Market Value at the time of exercise equal to the total Option Price (provided that the Shares which are tendered must have been held by the Participant for at least six (6) months prior to their tender to satisfy the Option Price); or (c) if permitted in the governing Award Agreement, by a combination of (a) and (b).

In addition, if permitted in the Award Agreement, the Participant may also be permitted to exercise Options pursuant to a "cashless exercise" procedure as permitted under the Federal Reserve Board's Regulation T, subject to securities law restrictions. In the event the Participant exercises pursuant to a "cashless exercise" procedure, any net gain on the "cashless exercise," after appropriate tax withholdings, shall be distributed to the Participant in the form of Shares.

As soon as practicable after receipt of a written notification of exercise and full payment, the Company shall deliver to the Participant, in the Participant's name, Share certificates in an appropriate amount based upon the number of Shares purchased under the Option(s). If either the purchase price or the Shares of Common Stock upon exercise of any Option or the tax withholding requirement is satisfied by tendering or withholding of Shares of Common Stock, only the number of Shares of Common Stock to be issued net of the Shares of Common Stock tendered or withheld shall be delivered.

6.7 Restrictions on Share Transferability. The Committee may impose such restrictions on any Shares acquired pursuant to the exercise of an Option granted under this Article 6 as it may deem advisable, including, without limitation, restrictions under applicable Federal securities laws, under the requirements of any stock exchange or market upon which such Shares are then listed and/or traded, and under any blue sky or state securities laws applicable to such Shares.

6.8 Termination of Employment. Each Participant's Option Award Agreement shall set forth the extent to which the Participant shall have the right to exercise the Option following termination of the Participant's employment with the Company. Such provisions shall be determined in the sole discretion of the Committee, shall be included in the Award Agreement entered into with each Participant, need not be uniform among all Options issued pursuant to this Article 6, and may reflect distinctions based on the reasons for termination of employment.

6.9 Nontransferability of Options.

(a) Incentive Stock Options. No ISO granted under the Plan may be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution. Further, all ISOs granted to a Participant under the Plan shall be exercisable during his or her lifetime only by such Participant.

(b) Nonqualified Stock Options. Except as otherwise provided in a Participant's Award Agreement, no NQSO granted under this Article 6 may be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution. Further, except as otherwise provided in a Participant's Award Agreement, all NQSOs granted to a Participant under this Article 6 shall be exercisable during his or her lifetime only by such Participant.

Article 7. Beneficiary Designation

Each Participant under the Plan may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit under the Plan is to be paid in case of his or her death before he or she received any or all of such benefit. Each such designation shall revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. In the absence of any such designation, benefits remaining unpaid at the Participant's death shall be paid to the Participant's estate.

Article 8. Deferrals

The Committee may permit or require a Participant to defer such Participant's receipt of the payment of cash or the delivery of Shares that would otherwise be due to such Participant by virtue of the exercise of an Option. If any such deferral election is required or permitted, the Committee shall, in its sole discretion, establish rules and procedures for such payment deferrals.

Article 9. Rights of Employees

9.1 Employment. Nothing in the Plan shall interfere with or limit in any way the right of the Company to terminate any Participant's employment at any time, nor confer upon any Participant any right to continue in the employ of the Company.

9.2 Participation. No Employee shall have the right to be selected to receive an Award under this Plan, or, having been so selected, to be selected to receive a future Award.

Article 10. Change in Control

10.1 Treatment of Outstanding Awards. Upon the occurrence of a Change in Control, unless otherwise specifically prohibited under applicable laws, or by the rules and regulations of any governing governmental agencies or national securities exchanges, any and all Options granted hereunder shall become immediately exercisable, and shall remain exercisable throughout their entire term.

10.2 Termination, Amendment, and Modifications of Change-in-Control Provisions. Notwithstanding any other provision of this Plan or any Award Agreement provision, the provisions of this Article 10 may not be terminated, amended, or modified on or after the date of a Change in Control to affect adversely any Award theretofore granted under the Plan without the prior written consent of the Participant with respect to said Participant's outstanding Awards.

Article 11. Amendment, Modification, and Termination

11.1 Amendment, Modification, and Termination. Subject to Section 10.2 herein, the Board may at any time and from time to time, alter, amend, suspend or terminate the Plan in whole or in part; provided, however, that no amendment which requires shareholder approval in order for the Plan to continue to comply with Rule 16b-3 under the Exchange Act, including any successor to such Rule, shall be effective unless such amendment shall be approved by the requisite vote of shareholders of the Company entitled to vote thereon.

The Committee shall not have the authority to cancel outstanding Awards and issue substitute Awards in replacement thereof.

11.2 Adjustment of Awards Upon the Occurrence of Certain Unusual or Nonrecurring Events. The Committee may make adjustments in the terms and conditions of, and the criteria included in, Awards in recognition of unusual or nonrecurring events (including, without limitation the events described in Section 4.3 hereof) affecting the Company or the financial statements of the Company or of changes in applicable laws, regulations, or accounting principles, whenever the Committee determines that such adjustments are appropriate in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the Plan.

11.3 Awards Previously Granted. No termination, amendment, or modification of the Plan shall adversely affect in any material way any Award previously granted under the Plan, without the written consent of the Participant holding such Award.

Article 12. Withholding

12.1 Tax Withholding. The Company shall have the power and the right to deduct or withhold, or require a Participant to remit to the Company, an amount sufficient to satisfy Federal, state and local taxes, domestic or foreign, required by law or regulation to be withheld with respect to any taxable event arising as a result of this Plan.

12.2 Share Withholding. With respect to withholding required upon the exercise of Options, Participants may elect, subject to the approval of the Committee, to satisfy the withholding requirement, in whole or in part, by having the Company withhold Shares having a Fair Market Value on the date the tax is to be determined equal to the minimum statutory total tax which could be withheld on the transaction. All such elections shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

Article 13. Indemnification

Each person who is or shall have been a member of the Committee, or of the Board, shall be indemnified and held harmless by the Company against and from any loss, cost, liability, or expense that may be imposed upon or reasonably incurred by him or her in connection with or resulting from any claim, action, suit, or proceeding to which he or she may be a party or in which he or she may be involved by reason of any action taken or failure to act under the Plan and against and from any and all amounts paid by him or her in settlement thereof, with the Company's approval, or paid by him or her in satisfaction of any judgment in any such action, suit, or proceeding against him or her provided he or she shall give the Company an opportunity, at its own expense, to handle and defend the same before he or she undertakes to handle and defend it on his or her own behalf. The foregoing right of indemnification shall not be exclusive of any other rights of indemnification to which such persons may be entitled under the Company's Articles of Incorporation or Bylaws, as a matter of law, or otherwise, or any power that the Company may have to indemnify them or hold them harmless.

Article 14. Successors

All obligations of the Company under the Plan with respect to Awards granted hereunder shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, of all or substantially all of the business and/or assets of the Company, or a merger, consolidation, or otherwise.

Article 15. Miscellaneous Provisions

15.1 Gender and Number. Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine; the plural shall include the singular and the singular shall include the plural.

15.2 Severability. In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

15.3 Requirements of Law. The granting of Awards and the issuance of Shares under the Plan shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

15.4 Securities Law Compliance. With respect to Insiders, transactions under this Plan are intended to comply with all applicable conditions of Rule 16b-3 or its successors under the Exchange Act. To the extent any provision of the plan or action by the Committee fails to so comply, it shall be deemed null and void, to the extent permitted by law and deemed advisable by the Committee.

15.5 Governing Law. To the extent not preempted by Federal law, the Plan, and all agreements hereunder, shall be construed in accordance with and governed by the laws of the state of South Dakota.

15.6 Unfunded Status of the Plan. The Plan is intended to constitute an "unfunded" Plan. With respect to any payments or deliveries of Shares not yet made to a Participant by the Company, nothing contained herein shall give any rights that are greater than those of a general creditor of the Company.

15.7 Purchase for Investment. The Committee may require each Participant purchasing or receiving Shares pursuant to an Option to represent to and agree with the Company in writing that such person is acquiring the Shares for investment and without a view to distribution or resale.

Exhibit 21

BLACK HILLS CORPORATION

SIGNIFICANT DIRECT AND INDIRECT SUBSIDIARIES

Black Hills Power, Inc., South Dakota corporation

Black Hills Energy Ventures, Inc., a South Dakota corporation

Black Hills Energy Capital, Inc., a Delaware corporation

Wyodak Resources Development Corp., a Delaware corporation

Adirondack Hydro Development Corporation, a Delaware corporation

Black Hills Capital Group, Inc., a South Dakota Corporation

Black Hills Coal Network, Inc., a South Dakota corporation

Black Hills Colorado, LLC, a Delaware corporation

Black Hills Energy Resources, Inc., a South Dakota corporation

Black Hills Exploration and Production, Inc., a Wyoming corporation

Black Hills FiberCom, LLC, a South Dakota corporation

Black Hills Fiber Systems, Inc., a South Dakota corporation

Black Hills Generation, Inc., a Wyoming corporation

Daksoft, Inc., a South Dakota corporation

Enserco Energy, Inc., a South Dakota corporation

Hudson Falls, LLC, a New York corporation

Landrica Development Company, a South Dakota corporation

South Glens Falls, LLC, a New York corporation

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report dated January 26, 2001 included or incorporation by reference in this Form 10-K, into the Company's previously filed Registration Statements, File Numbers 33-71130, 33-63059, 33-17451, 333-61969, 333-82787 and 333-30272.

ARTHUR ANDERSEN LLP

Minneapolis, Minnesota
March 15, 2001

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEER AND GEOLOGIST

As petroleum engineers, we hereby consent to the inclusion of the information included in this Form 10-K with respect to the oil and gas reserves of Black Hills Exploration and Production, Inc., the future revenues from such reserves, and the present value thereof, which information has been included in this Form 10-K in reliance upon the report of this firm and upon the authority of this firm as experts in petroleum engineering. We hereby further consent to all references to our firm included in this Form 10-K and to the incorporation by reference in the Registration Statements on Form S-8 Nos. 33-63059, 333-61969, 333-17451, 333-82787 and 333-30272 and the Registration Statement on Form S-3, No. 33-71130.

RALPH E. DAVIS ASSOCIATES, INC.

March 15, 2001

UT

YEAR
DEC-31-2000
DEC-31-2000
PER-BOOK
358,180,000
500,066,000
419,010,000
43,064,000
0
1,320,320,000
23,302,000
73,442,000
191,482,000
278,346,000
0
0
307,092,000
211,679,000
0
0
13,960,000
4,000,000
0
0
495,363,000
1,320,320,000
1,623,836,000
30,358,000
1,509,086,000
1,539,444,000
84,392,000
(1,202,000)
83,190,000
30,342,000
52,848,000
78,000
52,770,000
23,527,000
13,094,000
74,470,000
2.39
2.37