SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

Form 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

November 25, 2002
(Date of earliest event reported)

BLACK HILLS CORPORATION
(Exact name of Registrant as specified in its charter)

South Dakota	001-31303	46-0458824
(State of Incorporation)	(Commission File No.)	(IRS Employer Identification Number)

625 Ninth Street
P. O. Box 1400
Rapid City, South Dakota 57709
(Address of principal executive offices)

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

Not Applicable
(Former name or former address if changed since last report)

Item 5. Other Events

Black Hills Corporation announced today that our new independent public accountants, Deloitte & Touche LLP, have completed the audit of Black Hills Corporation's 2001, 2000 and 1999 financial statements that were originally audited by Arthur Andersen LLP. The reissued financial statements, including the report of Deloitte & Touche, are included in this Form 8-K. The net income and earnings per share in the reissued financial statements are unchanged from amounts previously reported in our Form 10-K. Black Hills Corporation issued a press release to announce the reissuance of its financial statements, which is included as Exhibit 99.1 and incorporated herein by reference.

Because Black Hills Corporation is reissuing the financial statements as of a current date, three areas of the reissued financial statements being filed today differ from Black Hills Corporation's 2001 Annual Report on Form 10-K as previously filed:

- o Discontinued operations presentation in the financial statements for the disposition of Black Hills Coal Network;
- o Reporting of energy trading results on a net basis; and
- o Disclosure of various subsequent events occurring since the 2001 financial statements were previously issued.

The discontinued operations disclosures and presentation changes in the reissued financial statements relate to Black Hills Corporation's second quarter 2002 plan to dispose of its coal marketing subsidiary, Black Hills Coal Network, Inc., and the completion of the sale in July 2002. Securities and Exchange Commission (SEC) rules require that once operations are reported as discontinued (as they were in the second and third quarter Form 10-Qs for 2002), subsequent financial statements must present such operations on a consistent basis. Discontinued operations disclosures have been added in a new footnote to Black Hills Corporation's reissued financial statements.

The trading reclassifications relate to new reporting requirements issued in 2002 by the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board. The EITF's decision requires that beginning in 2003 trading revenues and expenses be presented on a net basis. Black Hills elected to reclassify trading costs of approximately $1.0 billion, $1.3 billion and $0.6 billion in 2001, 2000 and 1999, respectively against trading revenues to present net trading margins in Black Hills Corporation's reissued income statements.

Given the current release of the reissued financial statements, reporting rules require that certain subsequent events in 2002 be disclosed to the extent they are relevant to the 2001, 2000 and 1999 financial statements. The reissued Black Hills Corporation financial statements include updated disclosures of various events in 2002.

The disclosure and presentation changes did not affect net income or earnings per share from amounts previously reported for Black Hills Corporation. Also, total assets, liabilities and shareholders' equity remain unchanged in the reissued financial statements from amounts previously reported for Black Hills Corporation. The discontinued operations and the trading reclassifications, however, did reduce total revenues of Black Hills Corporation from amounts previously reported and did reclassify other items on the income statements and balance sheets.

The following information is included as part of this Form 8-K:

SELECTED FINANCIAL DATA

Years ended December 31,	2001	2000	1999	1998	1997
TOTAL ASSETS (in thousands)	$1,658,767	$1,320,320	$668,492	$559,417	$508,741
PROPERTY AND INVESTMENTS (in thousands)					
Total property and investments	$1,564,664	$1,072,013	$699,928	$619,549	$598,306
Accumulated depreciation and depletion	328,325	277,797	245,992	229,942	197,179
Capital expenditures	594,142	173,517*	152,948	27,225	28,319
CAPITALIZATION (in thousands)					
Long-term debt	$415,798	$307,092	$160,700	$162,030	$163,360
Preferred stock equity	5,549	4,000	-	-	-
Common stock equity	509,615	278,346	216,606	206,666	205,403
Total capitalization	$930,962	$589,438	$377,306	$368,696	$368,763
CAPITALIZATION RATIOS					
Long-term debt	44.7%	52.1%	42.6%	43.9%	44.3%
Preferred stock equity	0.6	0.7	-	-	-
Common stock equity	54.7	47.2	57.4	56.1	55.7
Total	100.0%	100.0%	100.0%	100.0%	100.0%
TOTAL OPERATING REVENUES (in thousands)	$461,938	$292,142	$185,287	$180,674	$171,936
INCOME FROM CONTINUING OPERATIONS (in thousands)	$87,584	$52,812	$37,738	$25,808**	$32,359
DIVIDENDS PAID ON COMMON STOCK (in thousands)	$28,517	$23,527	$22,602	$21,737	$20,540
COMMON STOCK DATA (in thousands)					
Shares outstanding, average	25,374	22,118	21,445	21,623	21,692
Shares outstanding, average diluted	25,771	22,281	21,482	21,665	21,706
Shares outstanding, end of year	26,652	22,921	21,372	21,578	21,705
(in dollars)					
Basic earnings per average share -					
Continuing operations	$ 3.43	$ 2.39	$ 1.76	$ 1.19	$ 1.49
Discontinued operations	0.02	-	(0.03)	-	-
Total	$ 3.45	$ 2.39	$ 1.73	$ 1.19**	$ 1.49
Diluted earnings per average share -					
Continuing operations	$ 3.40	$ 2.37	$ 1.76	$ 1.19	$ 1.49
Discontinued operations	0.02	-	(0.03)	-	-
Total	$ 3.42	$ 2.37	$ 1.73	$ 1.19**	$ 1.49
Dividends paid per share	$ 1.12	$ 1.08	$ 1.04	$ 1.00	$ 0.95
Book value per share, end of year	$ 19.12	$ 12.14	$ 10.14	$ 9.58	$ 9.46
RETURN ON COMMON STOCK EQUITY (year-end)	17.2%	19.0%	17.1%	12.5%**	15.8%

*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

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 unregulated and regulated businesses have expanded significantly in recent years. Our integrated energy group, Black Hills Energy, Inc. (formerly Black Hills Energy Ventures, Inc.), produces and markets electric power and fuel. We produce and sell electricity in a number of markets, with a strong emphasis in the western United States. We also produce coal, natural gas and crude oil, primarily in the Rocky Mountain region, transport crude oil in Texas and market energy products nationwide. Our electric utility, Black Hills Power, Inc., serves an average of 59,600 customers in South Dakota, Wyoming and Montana. Our communications group offers state-of-the-art broadband communications services to over 23,700 residential and business customers in Rapid City and the northern Black Hills region of South Dakota through Black Hills FiberCom, LLC.

In 2002, we decided to discontinue operations in our coal marketing business due to challenges encountered in marketing our Wyodak coal from the Powder River Basin of Wyoming to East Coast markets. The non-strategic assets were sold effective August 1, 2002.

The following discussion should be read in conjunction with Item 7. - Management's Discussion and Analysis of Financial Condition and Results of Operations - included in our 2001 Annual Report on Form 10-K and with Item 2. - Management's Discussion and Analysis of Financial Condition and Results of Operations - included in our 2002 Periodic Reports on Form 10-Q that have been filed with the Securities and Exchange Commission.

Results of Operations

Consolidated Results

Overview

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

	2001	2000	1999
Revenue:			
Integrated energy	50%	38%	28%
Electric utility	46	59	72
Communications	4	3	-
	100%	100%	100%
Net income (loss) from continuing operations:			
Integrated energy	66%	56%	33%
Electric utility	52	70	73
Communications and other	(18)	(26)	(6)
	100%	100%	100%

During the second quarter of 2002, we adopted a plan to dispose of our coal marketing subsidiary, Black Hills Coal Network. The sale and disposal was finalized in July 2002. Results of operations have been restated to reflect the discontinued operations.

2001 Compared to 2000

Consolidated income from continuing operations for 2001 was $87.6 million, compared to $52.8 million in 2000, or $3.40 per average common share in 2001, compared to $2.37 per average common share in 2000. Income from discontinued operations was $0.5 million or $0.02 per share in 2001 compared to $36,000 in 2000. This equates to a 17.2 percent and 19.0 percent return on year-end common equity in 2001 and 2000, respectively. The return on year-end common equity in 2001 was diluted due to the net proceeds of $163 million from the public stock offering in 2001.

We reported record earnings in 2001, primarily due to strong natural gas marketing activity, increased fuel production, expanded power generation and increased wholesale off-system electric utility sales. Strong results in our integrated energy business group and electric utility business group were partially offset by losses in our communications business. Unusual energy market conditions stemming primarily from gas and electricity shortages in the West contributed to our strong financial performance in 2001 and 2000. There was an approximately $1.40 and $0.40 contribution to 2001 and 2000 earnings per share, respectively, due to prevailing prices of gas and electricity and unusually wide gas trading margins in the last part of year 2000 and first half of 2001.

Consolidated revenues were $461.9 million in 2001 compared to $292.1 million in 2000. Revenue increased in all segments. Daily volumes of natural gas marketed increased 22 percent from 860,800 million British thermal units per day in 2000 to 1,047,700 million British thermal units in 2001. Prices of financial and physical natural gas marketed decreased from an average of $2.77 per million British thermal units in 2000 to $2.14 per million British thermal units in 2001.

Earnings in 2001 included a $4.4 million after-tax charge ($0.17 per share) for a financial exposure to Enron Corporation and certain of its subsidiaries now in bankruptcy. The exposure is primarily related to the value of a long-term swap to provide natural gas to a power plant. We have taken action to mitigate this exposure. We are seeking authority to "net," or offset certain obligations with Enron and its subsidiaries, both payable and receivable, among our subsidiaries. If we are successful in these efforts, substantially all of the financial value of the fuel swap could be recovered, and we would not have any remaining exposure to Enron and its bankrupt subsidiaries.

Earnings in 2001 also reflect a $0.12 per share charge for employee stock bonus awards and the funding of a new non-profit foundation to advance our charitable and philanthropic endeavors. Both of these transactions were funded with Black Hills Corporation common stock.

2000 Compared to 1999

Consolidated income from continuing operations for 2000 was $52.8 million, compared to $37.7 million in 1999, or $2.37 per average common share in 2000, compared to $1.76 per average common share in 1999. This equates to a 19.0 percent and 17.1 percent return on year-end common equity in 2000 and 1999, respectively. Income (loss) from discontinued operations was $36,000 in 2000 compared to $(0.7) million or $(0.03) per share in 1999.

Earnings growth in 2000 was primarily due to strong natural gas marketing activity, increased fuel production, expanded power generation and increased wholesale off-system electric utility sales. Strong results in our integrated energy business group were partially offset by losses in our communications business. Unusual energy market conditions stemming primarily from gas and electricity shortages in the West during the last part of 2000 contributed to our strong financial performance. There was an approximately $0.40 contribution to 2000 earnings per share due to higher prevailing prices of gas and electricity and unusually wide gas trading margins.

Consolidated revenues were $292.1 million in 2000 compared to $185.3 million in 1999. The 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 integrated energy business group and increases in off-system sales by our electric utility. Prices of financial and physical natural gas marketed increased from an average of $1.38 per million British thermal units in 1999 to $2.77 per million British thermal units in 2000.

The following business group and segment information does not include intercompany eliminations.

Integrated Energy Group

	2001	2000	1999
		(in thousands)	
Revenue:			
Energy marketing	$ 83,884	$ 40,204	$ 7,640
Power generation	80,233	20,083	-
Oil and gas	33,408	20,328	13,052
Coal mining	31,800	30,530	31,095
Total revenue	229,325	111,145	51,787
Expenses	126,429	49,957	36,726
Operating income	$ 102,896	$ 61,188	$ 15,061
Net income	$ 57,930	$ 29,379	$ 12,554

The following is a summary of sales volumes of our coal, oil and natural gas production and various measures of power generation:

	2001	2000	1999
Tons of coal sold	3,518,000	3,050,000	3,180,000
Barrels of oil sold	445,500	334,000	318,000
Mcf of natural gas sold	4,619,500	3,274,000	2,791,000
Mcf equivalent sales	7,292,500	5,278,000	4,698,000
MWs of independent power capacity in service	617	250	-
MWs of independent power capacity under construction	364	470	-

The following is a summary of average daily energy marketing volumes:

	2001	2000	1999
Natural gas - MMBtus	1,047,700	860,800	635,500
Crude oil - barrels	36,500	44,300	19,270

2001 Compared to 2000

Net income of our integrated energy group nearly doubled in 2001 compared to 2000. These strong earnings resulted primarily from the unusually high prices of natural gas and high gas trading margins received in western markets during the first half of 2001, an increase in volumes marketed and fuel production, and expanded power generation.

In addition, in 2001, we reached a settlement of ongoing litigation with PacifiCorp concerning rights and obligations under a coal supply agreement under which PacifiCorp purchased coal from our coal mine to meet the coal requirements of the Wyodak Power Plant. As a result of this settlement, we recognized $5.6 million pre-tax non-operating income. In addition, we sold the "North Conveyor System" which resulted in a $2.6 million pre-tax gain. See Note 10 of Notes to Consolidated Financial Statements.

The integrated energy business group's revenues more than doubled to $229 million in 2001 compared to $111 million in 2000. The increase was related to a full year of independent power operations revenues related to the July 2000 acquisition of Indeck Capital and an increase in revenue from fuel production and gas marketing. Daily volumes of natural gas marketed increased 22 percent.

The integrated energy business group's total operating expenses increased 153 percent due to the expanded power production and increased volumes of fuel production and energy marketed. Operating income increased over 68 percent from 2000 levels due to higher production volumes.

2000 Compared to 1999

Net income of our integrated energy group increased 134 percent in 2000 compared to 1999. Operating expenses and operating income increased over 36 percent and 306 percent, respectively. 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, including the acquisition of Indeck Capital.

The integrated energy business group's revenues increased 115 percent in 2000 compared to 1999. The revenue increase was a direct result of gas and electricity shortages in the West Coast markets and the closing of the Indeck Capital acquisition. Daily volumes of natural gas marketed increased 35 percent.

Energy Marketing

Our energy marketing companies produced the following results:

	2001	2000	1999
		(in thousands)	
Revenue	$83,884	$40,204	$7,640
Operating income (loss)	53,662	24,113	(1,366)
Net income	34,566	13,973	486

2001 Compared to 2000

Earnings from the energy marketing segment increased $20.6 million due substantially to high gas margins received in the first half of 2001, as well as a 22 percent increase in natural gas average daily volumes marketed in 2001 compared to 2000. Revenues increased 109 percent from 2000 primarily due to higher daily volumes and the high gas margins.

The unusual energy market conditions stemming primarily from natural gas and electricity shortages in California and our ability to capture the higher margins contributed significantly to the strong financial performance.

2000 Compared to 1999

The strong increase in earnings in 2000 compared to 1999 was due to the unusual energy market conditions that existed in the last half of 2000 stemming from the natural gas and electricity shortages in California. Average daily volumes of natural gas marketed increased 35 percent in 2000 compared to 1999.

Power Generation

Our power generation segment produced the following results:

	2001	2000	1999
		(in thousands)	
Revenue	$80,233	$20,083	$ -
Operating income (loss)	27,455	20,374	(157)
Net income (loss)	1,576	3,242	(108)

2001 Compared to 2000

2001 reflects the first full year of operations of our power generation segment and our continued expansion of generation facilities. At December 31, 2001, we owned 617 net megawatts in currently operating plants. Of these 617 net megawatts, approximately 90 percent are under contracts or tolling arrangements with at least one year remaining. At year end, an additional 364 megawatts of generating capacity was under construction. Substantially all of this output will be sold pursuant to existing long-term contracts. The increased production capacity was offset by a $4.4 million after-tax charge for Enron exposure, additional reserves for exposure to western power markets and reduced water flow at hydro power plants in New York.

2000 Compared to 1999

Results from the power generation segment were not significant in 1999. In July 2000, we completed the acquisition of Indeck Capital, representing a significant advancement of our position in the power generation segment. At December 31, 2000, we owned 250 net megawatts of generating capacity in operating plants and had 470 megawatts under construction.

Oil and Gas

Oil and gas operating results were as follows:

	2001	2000	1999
		(in thousands)	
Revenue	$33,408	$20,328	$13,052
Operating income	15,193	7,906	3,978
Net income	10,197	4,992	2,462

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

	2001	2000	1999
Barrels of oil (in thousands)	4,055	4,413	4,109
Mcf of natural gas	24,071	18,404	19,460
Total in Mcf equivalents	48,401	44,882	44,114

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. We intend to increase our net proved reserves by selectively increasing our oil and gas exploration and development activities and by acquiring producing properties.

2001 Compared to 2000

Record net income in 2001 was primarily a result of a 27 percent increase in the average price received and a 38 percent increase in production volumes. The increase in gas reserves at December 31, 2001 was due to strong drilling results and reserve acquisitions.

In 2001, we acquired the operating and non-operating interests in 74 gas and oil wells located in Colorado and Wyoming from Stewart Petroleum Corporation of Denver, Colorado, for approximately $10 million. The acquired interest in these fuel assets represents approximately 10 billion cubic feet equivalent of natural gas. The acquisition increased our proved reserves by approximately 22 percent (based on year-end 2000 reserve estimates) and our current production rates by 10 percent.

2000 Compared to 1999

The increase in net income in 2000 was primarily the result of record natural gas prices, higher crude oil prices, and a significant increase in production volumes. The increase in economically recoverable oil reserves at December 31, 2000 was due to improved product prices.

Coal Mining

Coal mining results were as follows:

	2001	2000	1999
		(in thousands)	
Revenue	$31,800	$30,530	$31,095
Operating income	6,586	8,795	12,606
Net income	11,591	7,172	9,714

2001 Compared to 2000

Coal mining earnings increased $4.4 million as a result of a coal contract settlement, a gain on the sale of mining equipment and a 15 percent increase in tons sold, partially offset by lower average coal prices due to a coal contract settlement and an increase in mining related expenses. Tons of coal sold increased primarily due to the commencement of sales through our train load-out facility.

In 2001, we reached a settlement of ongoing litigation with PacifiCorp concerning rights and obligations under a coal supply agreement under which PacifiCorp purchased coal from our coal mine to meet the coal requirements of the Wyodak Power Plant. As a result of this settlement, we recognized $5.6 million pre-tax non-operating income. In addition, we sold the "North Conveyor System" which resulted in a $2.6 million pre-tax gain. See Note 10 of Notes to Consolidated Financial Statements.

2000 Compared to 1999

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

Electric Utility Group

	2001	2000	1999
		(in thousands)	
Revenue	$212,355	$173,308	$133,222
Operating expenses	128,247	105,100	80,936
Operating income	$ 84,108	$ 68,208	$ 52,286
Net income	$ 45,238	$ 37,178	$ 27,362

We currently have a winter peak load of 344 megawatts established in December 1998 and a summer peak of 392 megawatts established in August 2001. We own 395 megawatts of electric utility generating capacity and purchase an additional 65 megawatts under a long-term agreement (decreasing to 60 megawatts in 2002). At December 31, 2001, an additional 40 megawatts of generating capacity was under construction.

2001 Compared to 2000

Electric revenue increased 23 percent in 2001 compared to 2000. The increase in electric revenue in 2001 was primarily due to a 78 percent increase in wholesale off-system sales at an average price that was 27 percent higher than the average price in 2000. The increase in off-system sales was driven by high spot market prices for energy in early 2001, 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. Megawatt-hours generated from our oil-fired diesel and natural gas-fired combustion turbines were 440,368 in 2001, compared to 305,767 in 2000. 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 kilowatt-hour sales increased 2 percent in 2001. Residential and commercial sales increases of 3 percent in 2001 were partially offset by a slight decrease in industrial sales, primarily due to load reductions at Homestake Gold Mine. Degree days, a measure of weather trends, were 3 percent below normal in 2001 and 4 percent below 2000.

Revenue per kilowatt-hour sold was 7.0 cents in 2001 compared to 6.4 cents in 2000. The number of customers in the service area increased to 59,237 from 58,601 in 2000. The increase in the revenue per kilowatt-hour sold in 2001 is due to a 41 percent increase in wholesale off-system sales to 965,030 megawatt-hours and strong average wholesale power prices.

Electric utility operating expenses increased 22 percent in 2001 primarily due to a 29 percent increase in purchased power costs and a 14 percent increase in the average cost of generation. The increase in the average cost of generation was primarily associated with the operation of certain gas-fired combustion turbines.

In addition, 2001 results include a $2.0 million after-tax non-cash charge related to the contribution of Black Hills Corporation Common Stock to the newly formed Black Hills Corporation Foundation. This Foundation was created to enhance our longstanding practice of giving back to our communities. Through the Foundation, we may strengthen our service to our valued customers and fellow citizens for generations to come.

2000 Compared to 1999

Electric revenue increased 30 percent in 2000 compared to 1999. The increase in electric revenue in 2000 was primarily due to a 381 percent increase in wholesale off-system sales at an average price that was three times higher than the average price in 1999. The increase in off-system sales was driven by high spot market prices for energy in late 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. Megawatt-hours generated from our oil-fired diesel and natural gas-fired combustion turbines were 305,767 in 2000 compared to 25,882 in 1999.

Firm kilowatt-hour sales increased 3 percent. Residential and commercial sales increases of 4 percent 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.

Revenue per kilowatt-hour sold was 6.4 cents in 2000 compared to 5.4 cents in 1999. The number of customers in the service area increased to 58,601 in 2000 from 57,709 in 1999. The increase in the revenue per kilowatt-hour sold in 2000 is due to a 54 percent increase in wholesale off-system sales to 684,378 megawatt-hours and robust wholesale power prices.

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.

Communications Group

	2001	2000	1999
		(in thousands)	
Revenue - external*	$ 20,258	$ 7,689	$ 278
Revenue - intersegment*	4,250	3,682	3,145
Operating expenses	37,758	23,857	7,070
Operating loss	$(13,250)	$ (12,486)	$ (3,647)
Net loss	$(12,300)	$ (11,382)	$ (968)

*External revenue is revenue from our broadband communications business. Intersegment revenue is primarily revenue from our information services company derived from providing services to our other business segments. This intersegment revenue and associated expenses are eliminated in the consolidation process.

	2001	2000	1999
Residential customers	15,660	8,368	143
Business customers	2,250	646	110
Fiber optic backbone miles	242	210	200
Hybrid fiber coaxial cable miles	737	588	100

In September 1998, we formed our broadband communications business to provide facilities-based communications services for Rapid City and the northern Black Hills of South Dakota. As of December 31, 2001, we had invested approximately $125 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. We began serving communications customers in late 1999 and market our services to schools, hospitals, cities, economic development groups, and business and residential customers. The build-out is approximately 85 percent complete at December 31, 2001. Losses are expected to continue as we proceed with building the network and increasing the customer base. We expect our communications group will sustain approximately $7.0 million in net losses in 2002, with annual losses decreasing thereafter and profitability expected by 2004. The recovery of capital investment and future profitability are dependent primarily on our ability to attract new customers. If we are unable to attract additional customers or technological advances make our network obsolete, we could have a material write-down of assets.

2001 Compared to 2000

Our customer base nearly doubled in 2001 to 15,660 residential customers and 2,250 business customers. The increase in revenues from a larger customer base in 2001 was partially offset by increases in reserves for inventory and carrier billings and increased interest expense. Operating expense increased due to the expansion of the business. Operating performance in 2001 was in line with our expectations.

2000 Compared to 1999

Operating losses in 2000 were attributable to increased interest, depreciation and operating expenses. Operating losses in 1999 were primarily due to start-up organizational costs, increased depreciation expense and increased interest expense associated with the capital deployment.

Safe Harbor for Forward Looking Information

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 this Current Report on Form 8-K, 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.

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 among other things:

- unanticipated developments in the western power markets, including unanticipated governmental intervention, deterioration in the financial condition of counterparties, default on amounts due from counterparties, adverse changes in current or future litigation, adverse changes in the tariffs of the California Independent System Operator, market disruption and adverse changes in energy and commodity supply, volume and pricing and interest rates;
- 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;
- the State of California's efforts to reform its long-term power purchase contracts and recover refunds for alleged price manipulation;
- 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 by competitors;
- competition for new energy development opportunities;
- legal and administrative proceedings that influence our business and profitability;
- the effects on our business, including the availability of insurance, resulting from the terrorist actions on September 11, 2001, or any other terrorist actions or responses to such actions;
- the effects on our business resulting from the financial difficulties of Enron and other energy companies, including their effects on liquidity in the trading and power industry, and their effects on the capital markets views of the energy or trading industry, and our ability to access the capital markets on the same favorable terms as in the past;
- the effects on our business in connection with a lowering of our credit rating (or actions we may take in response to changing credit ratings criteria), including, increased collateral requirements to execute our business plan, demands for increased collateral by our current counterparties, refusal by our current or potential counterparties or customers to enter into transactions with us and our inability to obtain credit or capital in amounts or on terms favorable to us; and
- other factors discussed from time to time in our filings with the SEC.

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.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEPENDENT AUDITORS' REPORT

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, 2001 and 2000, and the related consolidated statements of income, common stockholders' equity and cash flows for the three years in the period ended December 31, 2001. 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 of America. 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, 2001, and 2000, and the results of their operations and their cash flows for each of the years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, which changed its method of accounting for certain commodity contracts and other derivatives.

DELOITTE & TOUCHE, LLP

Minneapolis, Minnesota,
November 15, 2002

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2001	2000	1999
	(in thousands, except per share amounts)		
Operating revenues	$461,938	$292,142	$185,287
Operating expenses:			
Fuel and purchased power	86,245	60,302	31,825
Operations and maintenance	65,556	46,054	36,463
Administrative and general	78,339	43,318	16,518
Depreciation, depletion and amortization	53,811	32,624	24,827
Taxes, other than income taxes	22,993	14,904	12,880
	306,944	197,202	122,513
Equity in earnings of unconsolidated subsidiaries	14,776	20,149	-
Operating income	169,770	115,089	62,774
Other income (expense):			
Interest expense	(39,479)	(30,136)	(15,226)
Interest income	2,372	7,067	3,597
Other expense	(4,759)	(2,278)	(2,920)
Other income	14,016	4,685	3,797
	(27,850)	(20,662)	(10,752)
Income from continuing operations before minority interest and income taxes	141,920	94,427	52,022
Minority interest	(4,186)	(11,273)	1,935
Income taxes	(50,150)	(30,342)	(16,219)
Income from continuing operations	87,584	52,812	37,738
Income (loss) from discontinued operations, net of taxes	493	36	(671)
Net income	88,077	52,848	37,067
Preferred stock dividends	(527)	(78)	-
Net income available for common stock	$ 87,550	$ 52,770	$ 37,067
Earnings per share of common stock:			
Basic-			
Continuing operations	$ 3.43	$ 2.39	$ 1.76
Discontinued operations	0.02	-	(0.03)
Total	$ 3.45	$ 2.39	$ 1.73
Diluted-			
Continuing operations	$ 3.40	$ 2.37	$ 1.76
Discontinued operations	0.02	-	(0.03)
Total	$ 3.42	$ 2.37	$ 1.73
Weighted average common shares outstanding:			
Basic	25,374	22,118	21,445
Diluted	25,771	22,281	21,482

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,	2001	2000
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 29,956	$ 24,290
Securities available-for-sale	3,550	2,113
Receivables (net of allowance for doubtful accounts of $5,913 and $3,631, respectively)	110,831	295,908
Derivative assets	38,144	62,531
Other assets	29,992	23,490
Assets of discontinued operations	10,090	12,009
	222,563	420,341
Investments	59,895	50,137
Property, plant and equipment	1,564,664	1,072,013
Less accumulated depreciation and depletion	(328,325)	(277,797)
	1,236,339	794,216
Other assets:		
Derivative assets	6,407	391
Goodwill	28,693	29,891
Intangible assets	86,528	16,281
Other	18,342	9,063
	139,970	55,626
	$1,658,767	$1,320,320
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 96,218	$ 241,799
Accrued liabilities	39,085	49,517
Current maturities of long-term debt	35,904	13,960
Notes payable	360,450	211,000
Derivative liabilities	42,681	57,968
Liabilities of discontinued operations	8,820	11,080
	583,158	585,324
Long-term debt, net of current maturities	415,798	307,092
Deferred credits and other liabilities:		
Federal income taxes	75,302	62,679
Derivative liabilities	7,119	3,532
Other	42,693	41,386
	125,114	107,597
Minority interest in subsidiaries	19,533	37,961
Commitments and contingencies (Notes 10, 11, 15 and 18)		
Stockholders' equity:		
Preferred stock - no par Series 2000-A; 21,500 shares authorized; issued and outstanding: 5,177 shares in 2001, 4,000 shares in 2000	5,549	4,000
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 26,890,943 shares in 2001 and 23,302,111 shares in 2000	26,891	23,302
Additional paid-in capital	240,454	73,442
Retained earnings	250,515	191,482
Treasury stock, at cost	(4,503)	(9,067)
Accumulated other comprehensive loss	(3,742)	(813)
	509,615	278,346
Total stockholders' equity	515,164	282,346
	$1,658,767	$1,320,320

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,	2001	2000	1999
		(in thousands)	
Operating activities:			
Net income available for common	$87,550	$52,770	$37,067
Principal non-cash items-			
(Income) loss from discontinued operations	(493)	(36)	671
Depreciation, depletion and amortization	53,811	32,624	24,827
Issuance of treasury stock for operating expenses (Note 4)	4,243	-	-
Provision for valuation allowances	9,632	3,232	(3)
Net change in derivative assets and liabilities	2,498	(1,422)	-
Gain on sales of assets	(2,587)	(3,736)	(2,541)
Deferred income taxes and investment tax credits	9,792	1,937	2,291
Undistributed earnings in associated companies	(9,287)	(3,672)	-
Minority interest	4,186	11,273	(1,935)
Change in operating assets and liabilities-			
Accounts receivable and other current assets	176,974	(208,078)	(2,941)
Accounts payable and other current liabilities	(157,061)	181,058	11,238
Other, net	(852)	1,691	5,427
	178,406	67,641	74,101
Investing activities:			
Property, plant and equipment additions	(378,465)	(134,855)	(100,629)
Payment for acquisition of net assets, net of cash acquired	(199,001)	(28,688)	-
Payment for acquisition of minority interest	(16,676)	-	-
Increase in investments	(471)	(9,974)	(52,319)
Proceeds from sales of assets	2,900	5,500	3,463
Available-for-sale securities purchased	-	-	(7,870)
Available-for-sale securities sold	-	4,660	22,959
	(591,713)	(163,357)	(134,396)
Financing activities:			
Dividends paid on common stock	(28,517)	(23,527)	(22,602)
Treasury stock issued (purchased)	321	(1,037)	(4,949)
Common stock issued	168,522	3,854	424
Increase in short-term borrowings, net	149,450	75,998	90,900
Long-term debt - issuance	144,610	60,082	-
Long-term debt - repayments	(13,960)	(1,330)	(1,330)
Subsidiary distributions to minority interests	(1,453)	(10,900)	-
	418,973	103,140	62,443
Increase in cash and cash equivalents	5,666	7,424	2,148
Cash and cash equivalents:			
Beginning of year	24,290	16,866	14,718
End of year	$ 29,956	$ 24,290	$ 16,866
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest	$ 39,563	$ 31,094	$ 15,098
Income taxes	$ 40,374	$ 18,880	$ 13,329
Noncash net assets acquired through issuance of common and preferred stock (Note 15)	$ 3,628	$ 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

(in thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Accumulated Other Comprehensive Income (loss)	Total
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
Total comprehensive income	-	-	-	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
Other comprehensive income, net of tax:								
Unrealized loss on available for sale securities	-	-	-	-	-	-	(813)	(813)
Total comprehensive income	-	-	-	52,848	-	-	(813)	52,035
Dividends on preferred stock	-	-	-	(78)	-	-	-	(78)
Dividends on common stock	-	-	-	(23,527)	-	-	-	(23,527)
Issuance of common stock	1,563	1,563	32,784	-	-	-	-	34,347
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
Comprehensive Income:								
Net income	-	-	-	88,077	-	-	-	88,077
Other comprehensive income, net of tax:								
Unrealized gain on available for sale securities	-	-	-	-	-	-	1,438	1,438
Initial impact of adoption of SFAS 133, net of minority interest	-	-	-	-	-	-	(4,510)	(4,510)
Fair value adjustment on derivatives designated as cash flow hedges, net of minority interest	-	-	-	-	-	-	143	143
Total comprehensive income	-	-	-	88,077	-	-	(2,929)	85,148
Dividends on preferred stock	-	-	-	(527)	-	-	-	(527)
Dividends on common stock	-	-	-	(28,517)	-	-	-	(28,517)
Issuance of common stock	3,589	3,589	167,012	-	-	-	-	170,601
Treasury stock issued, net	-	-	-	-	(142)	4,564	-	4,564
Balance at December 31, 2001	26,891	$ 26,891	$ 240,454	$ 250,515	239	$(4,503)	(3,742)	$509,615

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

(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 integrated energy, regulated electric utility and communications. The Company operates its integrated 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 and Black Hills Energy Resources related to energy marketing of natural gas and oil, respectively, and Black Hills Energy Capital and its subsidiaries and Black Hills Generation related to independent power activities, all aggregated for reporting purposes as Black Hills Energy (formerly 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 L.L.C. and Daksoft. For further descriptions of the Company's business segments, see Note 14.

In 2002, the Company decided to sell its coal marketing business. The non-strategic assets were sold effective August 1, 2002.

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to allowance for uncollectable accounts receivable, inventory obsolescence, realization of market value of derivatives due to commodity risk, intangible asset valuations and useful lives, proved oil and gas reserve volumes, employee benefit plans, environmental accruals and contingencies. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly owned and majority-owned subsidiaries and certain subsidiaries in which the Company's ownership interest may be less than 50 percent but represents voting control. 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 fuel sales to the Company's regulated subsidiary, Black Hills Power, Inc. in accordance with the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Total intercompany fuel sales not eliminated were $11.2 million, $9.7 million and $7.7 million in 2001, 2000 and 1999, respectively.

The Company owns 51 percent of the voting securities of Black Hills FiberCom, LLC (FiberCom). During 2000, FiberCom's operating losses reduced its unaffiliated members' equity below zero. At that point, the Company began to fund all operations and 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 the Company's equity to a positive amount.

As discussed in Note 15, the Company and its subsidiaries made several acquisitions during 2001 and 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 the accompanying Consolidated Statements of Income represents the share of income or loss of certain consolidated subsidiaries attributable to the minority shareholders of those subsidiaries. The minority interest in the accompanying Consolidated Balance Sheets reflect the amount of the underlying net assets of those certain consolidated subsidiaries attributable to the minority shareholders in those subsidiaries.

Regulatory Accounting

The Company's subsidiary, 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 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 the Neil Simpson II plant 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 could 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 that the continuing application of SFAS 71 is appropriate.

At December 31, 2001 and 2000, the Company had regulatory assets of $4.1 million. The Company also had regulatory liabilities of $4.2 million and $4.7 million at December 31, 2001 and 2000, respectively. The regulatory assets are included in Other assets and the regulatory liabilities are included in Other deferred credits and other liabilities on the Consolidated Balance Sheets.

Cash Equivalents

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

Securities Available-for-Sale

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 Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The unrealized gain or loss each period resulting from the changes in the securities' fair value is included as a component of accumulated other comprehensive income in common stockholders' equity.

Inventory

Materials, supplies and fuel are generally stated at the lower of cost or market on a first-in, first-out basis. During 2001, 2000 and 1999, provisions of $1.4 million, $1.5 million and $0, respectively, were charged to operations to write-down inventories at the Company's communications group to estimated net realizable value. Natural gas and oil inventories held in energy marketing companies are stated at market.

Property, Plant and Equipment

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 10.2, 9.7 and 10.0 percent during 2001, 2000 and 1999, respectively. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $7.5 million, $2.0 million and $1.2 million in 2001, 2000 and 1999, 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 resulting in an annual composite rate of 3.0 percent in 2001, 2.8 percent in 2000 and 3.1 percent in 1999. Non-regulated property, plant and equipment are depreciated on a straight-line basis using estimated useful lives ranging from 3 to 39 years. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method on volumes produced and estimated reserves.

Goodwill and Intangible Assets

Goodwill represents the excess of acquisition costs over the fair value of the net assets of acquired businesses and through 2001 was amortized on a straight-line basis over the estimated useful lives of such assets, which ranged 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 $3.8 million, $2.9 million and $3.3 million in 2001, 2000 and 1999, respectively. Accumulated amortization was $10.0 million, $6.1 million and $0.7 million at December 31, 2001, 2000 and 1999, respectively.

Impairment of Long-Lived Assets and Intangible Assets

The Company periodically evaluates whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of its long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, the Company would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, the Company would recognize an impairment loss. No impairment loss was recorded during 2001, 2000 or 1999.

Oil and Gas Operations

The Company accounts for its oil and gas activities under the full cost method. Under the full cost method, all 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 are subject to a "ceiling test" which limits these costs to the present value of future net cash flows discounted at 10 percent, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the net capitalized costs. Future net cash flows are estimated based on end-of-period spot market prices adjusted for contracted price changes. If the net capitalized costs exceed the full cost "ceiling" at period end, a permanent noncash write-down would be charged to earnings in that period unless known subsequent market price changes eliminate or reduce the indicated write-down. Given the volatility of oil and gas prices, the Company's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that a write-down of oil and gas properties could occur in the future. No "ceiling test" write-downs were recorded during 2001, 2000 or 1999.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Income taxes for consolidated subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss.

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. The Company classifies deferred tax assets and liabilities into current and noncurrent amounts based on the classification of the related assets and liabilities.

Revenue Recognition

Generally, revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured. Energy 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. For long-term non-utility power sales agreements, revenue is generally recognized as the lower of the amount billed or at the average rate expected over the life of the agreement.

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 primarily resulting from outstanding stock options and conversion of preferred shares. A reconciliation of Income from continuing operations and basic and diluted share amounts is as follows (in thousands):

	2001		2000		1999	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$87,584		$52,812		$37,738	
Less: preferred stock dividends	(527)		(78)		-	
Basic - available for common shareholders	87,057	25,374	52,734	22,118	37,738	21,445
Dilutive effect of:						
Stock options	-	223	-	86	-	37
Convertible preferred stock	527	148	78	56	-	-
Others	-	26	-	21	-	-
Diluted - available for common shareholders	$87,584	25,771	$52,812	22,281	$37,738	21,482

Reclassifications

Realized and unrealized gains and losses under energy trading contracts in the energy marketing segment have been reclassified to be presented on a net basis in Operating revenues on the accompanying Condensed Consolidated Statements of Income in accordance with Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." If the Company had reported these items on a gross basis, both operating revenues and fuel and purchased power costs would have been $1.0 billion, $1.3 billion and $0.6 billion higher for 2001, 2000 and 1999, respectively. The net presentation of these items rather than a gross presentation has no impact on operating income or net income.

Certain 2000 and 1999 amounts in the consolidated financial statements have been reclassified to conform to the 2001 presentation. These reclassifications had no effect on the Company's common stockholders' equity or results of operations, as previously reported.

Recently Issued Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 141, "Business Combinations" (SFAS 141) and No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. Under SFAS 142, goodwill and intangible assets with indefinite lives are no longer amortized but are reviewed annually (or more frequently if impairment indicators arise) for impairment. Intangible assets with a defined life will continue to be amortized over their useful lives (but with no maximum life). The amortization provisions of SFAS 142 apply to goodwill and intangible assets acquired after June 30, 2001. With respect to goodwill and intangible assets acquired prior to July 1, 2001, the Company was required to adopt SFAS 142 effective January 1, 2002. The cumulative effect of the change in accounting principle, net of tax at January 1, 2002, was a $896,000 benefit.

The pro forma effects of adopting SFAS 142 are as follows (in thousands, except per share amounts):

	2001	2000	1999
Net income as reported	$ 88,077	$ 52,848	$ 37,067
Add goodwill amortization	1,499	1,394	2,523
Adjusted net income	$ 89,576	$ 54,242	$ 39,590

	2001	2000	1999
Basic earnings per share	$ 3.45	$ 2.39	$ 1.73
Add goodwill amortization	0.06	0.06	0.12
Adjusted basic earnings per share	$ 3.51	$ 2.45	$ 1.85
Diluted earnings per share	$ 3.42	$ 2.37	$ 1.73
Add goodwill amortization	0.06	0.06	0.12
Adjusted diluted earnings per share	$ 3.48	$ 2.43	$ 1.85

In June 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement costs being capitalized as part of the carrying amount of the long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Management expects to adopt SFAS 143 effective January 1, 2003 and is currently evaluating the effects adoption will have on the Company's consolidated financial statements.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS 144). SFAS 144 supersedes FASB Statement 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (SFAS 121) and the accounting and reporting provisions of Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions" (APB 30). SFAS 144 establishes a single accounting model for long-lived assets to be disposed of by sale as well as resolves implementation issues related to SFAS 121. The Company was required to adopt SFAS 144 effective January 1, 2002. Adoption did not have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Change in Accounting Principle - Derivatives and Hedging Activities

In June 1998, the FASB issued Statement of Financial Accounting Standards 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. SFAS 133 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 hedge accounting for fair value and cash flow hedges. SFAS 133 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 20), "Accounting Changes."

On January 1, 2001, the Company adopted SFAS 133. Upon adoption, most of the Company's energy marketing activities previously accounted for under Emerging Issues Task Force Issue No. 98-10, "Accounting for Energy Trading and Risk Management Activities" (EITF 98-10) fell under the purview of SFAS 133. The effect of adoption on the energy marketing companies and risk management activities was not material because, unless otherwise noted, the energy marketing companies did not designate their risk management activities as hedge instruments. This "no hedge" designation resulted in these derivatives being measured at fair value and gains and losses recognized currently in earnings. This treatment under SFAS 133 was comparable to the accounting under EITF 98-10.

At January 1, 2001, the Company had certain non-trading energy contracts and interest rate swaps documented as cash flow hedges. These contracts were defined as derivatives under SFAS 133 and met the requirements for cash flow hedges. Because these contracts were documented as hedges prior to adoption, the transition adjustment was reported in accumulated other comprehensive income. The aggregated entry for these derivatives identified as cash flow hedges increased derivative assets by $0.9 million, increased the derivative liabilities by $11.2 million and decreased accumulated other comprehensive income by $10.3 million pre-tax and before minority interests.

(2) RISK MANAGEMENT ACTIVITIES

The Company's operations and financial results are impacted by numerous factors including, but not limited to, commodity price risk, interest rate risk and counterparty risk. The Company is exposed to commodity price variability in nearly all core energy marketing and trading businesses. In addition, fuel requirements at its gas-fired generation and its natural long position in crude oil and natural gas production introduce additional commodity price risk.

Energy Marketing Activities

The Company markets natural gas and crude oil in specific areas of the United States and Canada. The Company offers wholesale energy marketing and price risk management products and services to a variety of customers. These activities subject the Company to numerous risks including commodity price risk.

The Company has adopted Risk Management Policies and Procedures (RMP&P) covering all marketing activities. The RMP&P have been approved by the Company's Board of Directors and are routinely reviewed by the Audit Committee of the Board of Directors. The RMP&P include, but are not limited to, trader limits, position limits and credit exposure limits.

The Company employs risk management methods to mitigate its commodity price risk. As a general policy, the Company only permits speculation with limited "open" positions as defined in the RMP&P. Therefore, substantially all of its marketing activities are fully hedged or back-to-back positions; in other words, each sale is matched with a purchase.

To maintain compliance with the RMP&P and mitigate its commodity price risk, the Company routinely utilizes fixed price forward purchase and sales contracts and over-the-counter swaps and options. The Company attempts to balance its fixed price physical and financial purchase and sale commitments in terms of volume and timing of performance and delivery obligations. However, the Company may at times have a bias in the market, within established guidelines, resulting from the management of its portfolio. In addition, the Company may, at times, be unable to fully hedge its portfolio for certain market risks as a result of marketplace illiquidity and other factors.

The Company's energy marketing operations are accounted for under mark-to-market accounting. The Company records its fair values as either Derivative assets and/or Derivative liabilities on the accompanying Consolidated Balance Sheet. The net gains or losses are recorded as Revenues in the accompanying Consolidated Statements of Income.

The contract or notional amounts and terms of the Company's derivative commodity instruments held for trading purposes at December 31, 2001 and 2000, are set forth below:

	2001		2000	
(thousands of MMBtu's)	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
Natural gas basis swaps purchased	9,882	1	25,578	2
Natural gas basis swaps sold	10,696	1	26,060	2
Natural gas fixed-for-float swaps purchased	10,646	2	6,476	1
Natural gas fixed-for-float swaps sold	11,815	2	7,361	1
Natural gas swing swaps purchased	465	1	-	-
Natural gas swing swaps sold	930	1	-	-
Natural gas physical purchases	13,159	1	-	-
Natural gas physical sales	19,339	1	-	-
(thousands of barrels)				
Crude oil purchased	3,139	1	2,186	1
Crude oil sold	3,142	1	2,530	1

As required under SFAS 133, derivatives and energy trading activities were marked to fair value on December 31, 2001, and the gains and/or losses recognized in earnings. The amounts related to the accompanying Consolidated Balance Sheets and Statements of Income as of December 31, 2001 and 2000, are as follows (in thousands):

December 31, 2001	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain
Natural gas	$29,755	$ 661	$25,437	$ 953	$4,026
Crude Oil	6,267	-	5,497	-	770
	$36,022	$ 661	$30,934	$ 953	$4,796
December 31, 2000					
Natural gas	$61,008	$ 391	$56,968	$ 3,532	$ 899
Crude oil	1,523	-	1,000	-	523
	$62,531	$ 391	$57,968	$ 3,532	$1,422

At December 31, 2001, the Company had a mark to fair value unrealized gain of $4.8 million for its energy marketing activities. Of this amount, $5.1 million was current and $(0.3) million was non-current. The current portion of unrealized gains is associated with back to back transactions in which each sale is matched to a purchase. The Company anticipates that substantially all of the current portion of unrealized gains for these transactions will be realized during the next twelve months. Conversely, estimated and actual realized gains or losses related to open positions will likely change during 2002 as market prices change from the December 31, 2001 estimates.

Non-trading Energy Activities

The Company produces natural gas and crude oil through its exploration and production activities. These natural long positions, or unhedged open positions, introduce commodity price risk and variability in cash flows for the Company. The Company employs risk management methods to mitigate this commodity price risk and preserve its cash flows. The Company has adopted guidelines covering hedging for its natural gas and crude oil production. These guidelines have been approved by the Company's Board of Directors and are routinely reviewed by its Audit Committee.

To mitigate commodity price risk and preserve cash flows, the Company uses over-the-counter swaps and options. These derivative instruments fall under the purview of SFAS 133 and the Company elects to utilize hedge accounting as allowed under this Statement.

At December 31, 2001, the Company had a portfolio of swaps to hedge portions of its crude oil and natural gas production. These transactions were previously identified as cash flow hedges, properly documented, and met prospective effectiveness testing. At year-end, these transactions met retrospective effectiveness testing criteria and retained their cash flow hedge status.

At December 31, 2001, the derivatives were marked to fair value and were recorded in Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income and the ineffective portion was reported in earnings.

On January 1, 2001 (the transition adjustment date for SFAS 133 adoption) and December 31, 2001, the Company had the following swaps and related balances (in thousands):

	Notional*	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Accumulated Other Comprehensive Income (Loss)	Earnings
January 1, 2001								
Crude oil swaps	294,000	2	$ 33	$ 151	$ -	$ -	$ 184	$ -
Crude oil options	120,000	1	472	-	-	-	472	-
Natural gas swaps	1,581,000	1	-	-	3,411	-	(3,411)	-
			$ 505	$ 151	$3,411	$ -	$(2,755)	$ -
December 31, 2001								
Crude oil swaps	90,000	1	$ 529	$ -	$ -	$ -	$ 529	$ -
Natural gas swaps	1,216,000	1	1,593	-	-	-	1,463	130
			$ 2,122	$ -	$ -	$ -	$ 1,992	$ 130

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*crude in bbls, gas in MMBtu's

Most of the Company's crude oil and natural gas hedges are highly effective, resulting in very little earnings impact prior to realization. During 2001, the Company recorded $0.1 million earnings due to ineffectiveness for certain natural gas swaps due to basis risk.

All existing hedges at December 31, 2001 expire during the year ended December 31, 2002. The unrealized earnings gains or losses currently recorded in accumulated other comprehensive income are expected to be realized in earnings during 2002. Based on December 31, 2001 market prices, $2.0 million will be realized and reported in earnings during 2002. These estimated realized gains for 2002 were calculated using December 31, 2001 market prices. Estimated and actual realized gains will likely change during 2002 as market prices change.

In addition, the Company acquired several natural gas swaps when it completed the Las Vegas Cogeneration acquisition on August 31, 2001 (Note 15). The project has a long-term fixed price power sales agreement and an index-priced natural gas purchase contract for 5,000 MMBtus per day through April 30, 2010. These swaps fix the long-term purchase price of the index-priced natural gas purchase contract. At acquisition close, the fair value of these swaps was $6.0 million. These swaps were executed with Enron North America Corp. (Enron), which is currently in bankruptcy proceedings.

These swaps are derivatives under SFAS 133. The Company elected to treat these derivatives as cash flow hedges so that any gains or losses on the fair values of the swaps could be deferred and subsequently recognized when the underlying hedged natural gas was consumed in the plant. The swaps were properly documented and met the criteria for cash flow hedges.

During the fourth quarter of 2001, the Company determined that it was probable that Enron would default on its obligations to the Company in conjunction with these swaps. Upon that determination, the Company ceased to account for these swaps as cash flow hedges. In addition, the Company recognized a $6.0 million pre-tax charge to income in recognition of Enron's probable performance default and resulting consequence that the Company would not receive payment for these amounts.

Financing Activities

The Company engages in activities to manage risks associated with changes in interest rates. The Company has entered into floating-to-fixed interest rate swap agreements to reduce its exposure to interest rate fluctuations associated with its floating rate debt obligations. At December 31, 2001, these hedges met effectiveness testing criteria and retained their cash flow hedge status. At December 31, 2001, the Company had $291.4 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of five years and a fair value of $(14.4) million. These hedges are substantially effective and any ineffectiveness was immaterial.

In addition to the above interest rate swaps, the Company has entered into a $100 million forward starting floating-to-fixed interest rate swap to hedge the anticipated floating rate debt financing related to the Company's Las Vegas Cogeneration expansion. At December 31, 2001, the swap had a fair market value of $2.3 million. This swap terminated during the second quarter 2002 and resulted in a $1.1 million gain. This swap was treated as a cash flow hedge and accordingly in the second quarter of 2002 the resulting gain was carried in Accumulated Other Comprehensive Income and was to be amortized over the life of the anticipated long-term financing. In the third quarter of 2002, this cash flow hedge was determined to be ineffective due to uncertainties about the eventual timing and form of financing for this project. As a result, $1.1 million was taken into earnings. The gain was offset by the expensing of approximately $1.0 million of deferred financing costs related to the anticipated financing.

At December 31, 2001, the Company had $655.8 million of outstanding, floating rate debt, of which $364.4 million was not offset with interest rate swaps transactions that effectively convert the debt to fixed rate.

On January 1, 2001 (the transition adjustment date for SFAS 133 adoption) and on December 31, 2001, the Company's interest rate swaps and related balances were as follows (in thousands):

	Current Notional Amount	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Accumulated Other Comprehensive Income (Loss)
January 1, 2001								
Swaps on project financing	$127,416	7.38%	5	$ -	$ 265	$ 2,440	$5,332	$ (7,507)
December 31, 2001								
Swaps on project financing	$316,397	5.85%	4	$ -	$5,746	$10,212	$5,949	$(10,415)
Swaps on corporate debt	75,000	4.45%	3	-	-	1,535	217	(1,752)
Total	$391,397			$ -	$5,746	$11,747	$6,166	$(12,167)

The Company anticipates a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2002. Based on December 31, 2001 market interest rates, $11.7 million will be realized as additional interest expense during 2002. Estimated and realized amounts will likely change during 2002 as market interest rates change.

Credit Risk

Credit risk relates to the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. The Company maintains credit policies with regards to its counterparties that the Company believes limit its overall credit risk.

For its energy marketing, energy production and risk management activities, the Company attempts to mitigate its credit risk by conducting a majority of its business with investment grade companies, obtaining netting agreements where possible and securing its exposure with less creditworthy counterparties through parental guarantees, prepayments and letters of credit.

At the end of the year, the Company's credit exposure (exclusive of regulated retail customers and communications) was concentrated with investment grade companies. Approximately 85 percent of the Company's credit exposure was with investment grade companies. For the 15 percent credit exposure with non-investment grade rated counterparties, approximately 60 percent of this exposure was supported through letters of credit, prepayments, parental guarantees or asset liens.

(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:

o A 33.33 percent interest (see Note 18) 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 $7.0 million and $6.9 million as of December 31, 2001 and 2000, respectively. The partnership had assets of $23.8 million and $22.0 million, liabilities of $2.8 million and $1.0 million as of December 31, 2001 and 2000, and net income of $3.4 million and $2.8 million during 2001 and 2000, respectively.

- A 12.6 percent, 6.9 percent and 5.3 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 $10.0 million and $8.4 million at December 31, 2001 and 2000, respectively, which includes $1.9 million and $2.1 million, respectively, that represents the cost of the investment over the underlying net assets of the funds. This excess is being amortized over 10 years. As of and for the year ended December 31, 2001, the funds had assets of $215.1 million, liabilities of $0.7 million and net income of $37.2 million. 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.

- A 50 percent interest in two natural gas-fired co-generation facilities located in Rupert and Glenns Ferry, Idaho. The Company's carrying amount in the investment is $3.9 million and $4.1 million as of December 31, 2001 and 2000, respectively, 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, 2001, these projects had assets of $25.6 million, liabilities of $19.0 million and a net loss of $(0.4) million. 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.

- A direct and indirect ownership of approximately 53 percent (32 percent in 2000) representing 50 percent voting control, of Harbor Cogeneration Company (see Note 18). Harbor Cogeneration owns a 98 megawatt gas-fired plant (expanded from 80 megawatts in 2000) located in Wilmington, California. At December 31, 2001 and 2000, the Company's carrying amount in the investment was $47.9 million and $42.2 million, respectively, which includes $12.2 million and $13.7 million, respectively, which 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, 2001, Harbor had assets of $51.4 million, liabilities of $0.4 million and net income of $10.1 million. 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

Common Stock Offering

During 2001, the Company completed a public offering of its common stock through which approximately 3.4 million shares were sold at $52 per share. Net proceeds were approximately $163 million after commissions and expenses. The proceeds were used to repay a portion of current indebtedness under revolving credit facilities, to fund various power plant construction costs and for general corporate purposes.

Employee Stock Incentive and Employee Stock Purchase Plans

The Company has several employee stock incentive plans (Stock Incentive Plans), which allow for the granting of stock options with exercise prices equal to the stock's fair 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 123). Accordingly, no compensation cost has been recognized.

The Company may grant options for up to 2,200,000 shares of common stock under the Stock Incentive Plans. The Company has 1,037,882 shares available to grant at December 31, 2001. 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, 2001, 2000 and 1999, and changes during the years then ended are as follows:

	2001		2000		1999	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	914,917	$23.43	431,450	$21.35	292,700	$20.29
Granted	203,000	$37.09	492,500	$25.22	140,250	$23.58
Forfeited	(30,834)	$22.13	(4,000)	$23.25	(1,500)	$23.06
Exercised	(94,211)	$20.41	(5,033)	$21.33	-	$ -
Balance at end of year	992,872	$26.55	914,917	$23.43	431,450	$21.35
Exercisable at end of year	445,252	$22.76	292,891	$20.43	182,400	$19.19

Details of outstanding options at December 31, 2001 are as follows:

Option Exercise Prices	Shares Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Shares Exercisable	Weighted Average Exercise Price
$16.67 to $25.00	680,872	$21.75	7.4 years	407,600	$21.45
$25.01 to $37.50	151,000	$31.04	9.8 years	3,166	$28.63
$37.51 to $55.36	161,000	$42.65	9.1 years	34,486	$37.69

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:

	2001	2000	1999
Weighted average fair value of options at grant date	$10.77	$3.88	$4.16
Weighted average risk-free interest rate	5.92%	6.30%	6.68%
Weighted average expected price volatility	34.92%	20.60%	19.85%
Weighted average expected dividend yield	2.90%	4.20%	4.50%
Expected life in years	10	10	10

Had compensation cost been determined consistent with SFAS 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 (unaudited):

	2001	2000	1999
	(in thousands, except per share amounts)		
Net income available for common:			
As reported	$87,550	$52,770	$37,067
Pro forma	$86,845	$52,432	$36,877
Earnings per share:			
As reported -			
Basic			
Continuing operations	$ 3.43	$ 2.39	$1.76
Discontinued operations	0.02	-	(0.03)
Total	$ 3.45	$ 2.39	$1.73
Diluted			
Continuing operations	$ 3.40	$ 2.37	$1.76
Discontinued operations	0.02	-	(0.03)
Total	$ 3.42	$ 2.37	$1.73
Pro forma -			
Basic			
Continuing operations	$ 3.40	$ 2.38	$1.75
Discontinued operations	0.02	-	(0.03)
Total	$ 3.42	$ 2.38	$1.72
Diluted			
Continuing operations	$ 3.37	$ 2.35	$1.75
Discontinued operations	0.02	-	(0.03)
Total	$ 3.39	$ 2.35	$1.72

The Company maintains the ESPP Plan under which it sells shares to employees at 90 percent of the stock's market price on the offering date. The Company issued 48,368, 21,394 and 19,565 shares of common stock under the ESPP Plan in 2001, 2000 and 1999, respectively. At December 31, 2001, 177,808 shares are reserved and available for issuance under the ESPP Plan. The fair value per share of shares sold in 2001 was $22.50 on the offering date.

Employee Stock Awards

During 2001, the Company issued a total of 36,550 common shares as a stock bonus award to its non-officer employees. The bonus was grossed up to cover related employee taxes. The total pre-tax compensation charge recognized by the Company was $1.9 million, which is based on the market value of the stock on the grant date. Additionally, approximately 18,000 common shares will be issued at the two-year anniversary date of the original award, contingent on certain vesting restrictions. Pre-tax compensation cost related to this portion of the award is estimated to be $0.9 million and is being expensed over the two-year vesting period.

During 2001, the Company issued 12,177 restricted common shares (net of 4,512 common shares forfeited) to certain officers. The shares carry a restriction on the officer's ability to sell the shares, until the shares vest. The shares vest one-third per year over three years, contingent on employment. Pre-tax compensation cost related to the award was $0.7 million, which is being expensed over the three-year vesting period.

Nonemployee stock award

During 2001, the Company issued 100,000 common shares as a charitable contribution to the newly formed not-for-profit entity, Black Hills Corporation Foundation. The charitable contribution cost included in "Other, net" on the 2001 Consolidated Statement of Income was $3.1 million, which is based on the stock market value on the grant date.

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 2001, 2000 and 1999. At December 31, 2001, 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 2001 and 2000, the Company issued 5,177 preferred shares in the Indeck Capital acquisition and the related "earn-out" provisions. 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):

	2001	2000
Fixed rate first mortgage bonds:		
6.50% due 2002	$ 15,000	$ 15,000
9.00% due 2003	2,176	3,215
8.06% due 2010	30,000	30,000
9.49% due 2018	4,840	5,130
9.35% due 2021	33,300	35,000
8.30% due 2024	45,000	45,000
	130,316	133,345
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	3,870	3,911
	28,370	28,411
Project financing floating rate debt (a):		
Fountain Valley project at 3.29% (b) due 2006	144,581	-
Hudson Falls at 3.7% (b) due 2010	69,479	74,147
South Glens Falls at 3.7% (b) due 2009	24,008	26,124
Valmont and Arapahoe at 3.31% (b) due 2010	54,948	59,025
	293,016	159,296
Total long-term debt	451,702	321,052
Less current maturities	(35,904)	(13,960)
Net long-term debt	$415,798	$307,092

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(a) Approximately 74 percent of the December 31, 2001 balance has been hedged with interest rate swaps moving the floating rates to fixed rates with a weighted average interest rate of 5.85 percent (see Note 2-Risk Management Activities).

(b) Interest rates are presented as of December 31, 2001.

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 were in compliance with or have obtained amendments and waivers effective at December 31, 2001.

Scheduled maturities of long-term debt for the next five years are: $35.9 million in 2002, $22.4 million in 2003, $23.1 million in 2004, $24.7 million in 2005 and $137.3 million in 2006.

(7) NOTES PAYABLE

The Company has committed lines of credit with various banks totaling $400 million at December 31, 2001 and $290 million at December 31, 2000. At December 31, 2001, these lines consist of a $200 million revolving credit facility with a term of 364 days, which terminates August 27, 2002, and a $200 million revolving credit facility with a term of three years, which terminates on August 27, 2004. The Company had $360 million of borrowings and $33.0 million of letters of credit and $211 million of borrowings and $20.6 million of letters of credit issued on the lines at December 31, 2001 and 2000, respectively. The Company had no compensating balance requirements associated with these lines of credit.

At December 31, 2001, the above facilities contained ratings trigger provisions that, if violated, would have been considered an event of default and would have allowed the lender to terminate the remaining commitment and accelerate the principal and interest outstanding to become immediately due. The Company would have been considered in violation of these ratings trigger provisions if its Standard & Poor's (S&P) Rating ceased to be at least BBB- or its Moody's Rating ceased to be at least Baa3. In addition, certain of the Company's interest rate swap agreements with a $150.0 million notional amount and a $0.7 million fair value at December 31, 2001 include cross-default provisions. These provisions would allow the counterparty the right to terminate the swap agreement and liquidate at a prevailing market rate, in the event of default. The facilities that had rating triggers were amended during the second quarter of 2002 to remove default provisions pertaining to credit rating status. The Company's S&P and Moody's Ratings were BBB and A3, respectively at December 31, 2001.

In addition to the above lines of credit, at December 31, 2001, Enserco Energy (Enserco) has a $75.0 million ($90.0 million at December 31, 2000) uncommitted, discretionary line of credit to provide support for the purchases of natural gas. The line of credit is secured by all of Enserco's assets. The Company and its other subsidiaries provide no guarantees to the lender. At December 31, 2001 and 2000, there were outstanding letters of credit issued under the facility of $36.2 million and $69.8 million, respectively, with no borrowing balances on the facility.

Black Hills Energy Resources (BHER) has a $25.0 million uncommitted, discretionary credit facility secured by all of its assets. The transactional line of credit provides credit support for the purchases of crude oil of BHER. The Company and its other subsidiaries provide no guarantees to the lender. At December 31, 2001 and 2000, BHER had letters of credit outstanding of $4.4 million and $8.5 million, respectively, with no borrowing balances on the facility.

Our credit facilities contain certain restrictive covenants. The Company and its subsidiaries had complied with all the covenants at December 31, 2001.

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 (4.75 percent at December 31, 2001) to prime rate plus 1.0 percent, or (ii) on a London Interbank Offered Rate (LIBOR) based borrowing rate varying from LIBOR plus 0.6 percent to LIBOR plus 0.625 percent. The one-month LIBOR rate at December 31, 2001 was 1.87 percent. In addition to interest on outstanding borrowings, the credit facilities contain a 0 percent to 0.15 percent annual facility fee on the total facility amount, and an annual utilization fee ranging from 0 percent to 0.125 percent of the total used facility amount.

The Company has entered into floating-to-fixed interest rate swaps to hedge a portion of its exposure to interest rate fluctuations with the above floating rate obligations. See Note 2 for further details.

(8) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2001		2000	
	(in thousands)			
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 29,956	$ 29,956	$ 24,290	$ 24,290
Securities available-for-sale	$ 3,550	$ 3,550	$ 2,113	$ 2,113
Derivative financial instruments - assets	$ 44,551	$ 44,551	$ 62,922	$ 62,922
Derivative financial instruments - liabilities	$ 49,800	$ 49,800	$ 61,500	$ 61,500
Notes payable	$360,450	$360,450	$211,000	$211,000
Long-term debt	$451,702	$469,787	$321,052	$337,446

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.

Securities Available-for-Sale

The fair value of the Company's investments equals the quoted market price. The Company has classified all of its marketable securities as available-for-sale as of December 31, 2001 and 2000. An unrealized gain on the Company's investments of $1.4 million and an unrealized loss of $0.8 million was recorded as of December 31, 2001 and 2000, respectively.

Derivative Financial Instruments

These instruments are carried at fair value. Descriptions of the various instruments the Company uses and the valuation method employed are available in Note 2 of these Consolidated Financial Statements.

Notes Payable

The carrying amount approximates fair value due to their variable interest rates with short reset periods.

Long-Term Debt

The fair value of the Company's long-term debt is estimated based on quoted market rates for 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.

(9) JOINTLY OWNED FACILITY

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, 2001, the Company's investment in the Plant included $71.7 million in electric plant and $22.8 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. The Company's share of direct expenses of the Plant was $5.9 million, $5.6 million and $4.9 million for the years ended December 31, 2001, 2000 and 1999, respectively, and is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 10, the Company's coal mining subsidiary, Wyodak Resources, supplies coal to the Plant under an agreement expiring in 2022. This coal supply agreement is collateralized by a mortgage on and a security interest in some of Wyodak Resources' coal reserves. Under the coal supply agreement, Pacific Power is obligated to purchase a minimum of 1,500,000 tons of coal each year of the contract term, subject to adjustment for planned outages. Wyodak Resources' sales to the Plant were $21.0 million, $23.2 million and $24.9 million for the years ended December 31, 2001, 2000 and 1999, respectively.

(10) COMMITMENTS AND CONTINGENCIES

Off Balance Sheet Lease

The Company's subsidiary, Black Hills Generation, has entered into an Agreement for Lease and Lease with Wygen Funding, Limited Partnership for the Wygen Plant, a 90 megawatt coal-fired power plant under construction in Campbell County, Wyoming. Wygen Funding is a special purpose entity that owns the Wygen Plant and has financed the project. Total cost of the project is estimated to be approximately $130 - $140 million. Neither Wygen Funding, its owners, nor its officers are related to the Company, and other than the lease transaction and obligations incurred as a result of this transaction, there is no obligation to provide additional funding or issue securities to Wygen Funding. Lease payments are based on final construction and financing costs and are currently estimated to be approximately $6.5 million per year based on five-year treasury rates. Lease payments will begin after substantial completion of construction scheduled for first quarter 2003. The lease will be accounted for as an operating lease. The initial lease term is five years with two five-year renewal options and includes a purchase option equal to the adjusted acquisition cost. The adjusted acquisition cost is essentially equal to the final construction cost of the project. If the Company elects to terminate or not renew the lease and not purchase the project, then it must make a termination payment equal to the lesser of 83.5 percent of the adjusted acquisition cost or the shortfall of proceeds received from the owner's sale of the project relative to the owner's cost. Black Hills Corporation has guaranteed the Agreement for Lease and Lease.

Power Purchase Agreement - Pacific Power

In 1983, the Company entered into a 40 year power purchase 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 $13.9 million in 2001, $14.6 million in 2000 and $17.8 million in 1999.

Long-Term Power Sales Agreements

The Company, through its subsidiaries, has the following significant long-term power sales contracts:

- The Company has long-term power sales contracts with the Public Service Company of Colorado (PSCC) for the output of several of its plants. All of the output of the Company's Fountain Valley, Arapahoe and Valmont gas-fired facilities, totaling 400 megawatts in operation plus an additional 50 megawatts combined-cycle expansion currently under construction, is included under the contracts which expire in 2012. The contracts are tolling arrangements in which the Company assumes no fuel price risk.

- Beginning September 1, 2001, the Company has a ten year power sales contract with Cheyenne Light, Fuel and Power (CLF&P) for the output of the 40 megawatt gas-fired Gillette CT. The contract is a tolling arrangement in which the Company assumes no fuel risk. In addition, the Company entered into a ten year contract with CLF&P for 60 megawatts of contingent capacity from the 90 megawatt Wygen Plant, currently under construction. Twenty megawatts of the remaining capacity of this plant has been sold under a ten year contract with the Municipal Electric Agency of Nebraska.

- The Company has secured long-term contracts for the output of the 277 megawatt Las Vegas facility that was acquired during the third quarter of 2001. See Note 15 for a description of the facility and the related long-term contracts.

- Various long-term contracts with Niagara Mohawk Power Corporation have been entered into to sell the output of several of the Company's hydroelectric projects located in upstate New York. The Company's net ownership of capacity under contract is approximately 21 megawatts with contracts expiring between 2028 and 2032. There are additional contracts on plants with a net ownership capacity of approximately 21 megawatts that expire during 2002 and 2003.

Reclamation Liability

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, 2001, accrued reclamation costs included in Other liabilities on the accompanying Consolidated Balance Sheets were approximately $18.2 million.

Legal Proceedings

Settlement

On April 3, 2001, the Company reached a settlement of ongoing litigation with PacifiCorp filed in the United States District Court, District of Wyoming, (File No. 00CV-155B). The litigation concerned the parties' rights and obligations under the Further Restated and Amended Coal Supply Agreement dated May 5, 1987, under which PacifiCorp purchased coal from the Company's coal mine to meet the coal requirements of the Wyodak Power Plant. The Settlement Agreement provided for the dismissal of the litigation, with prejudice, coupled with the execution of several new coal-related agreements between the parties discussed below. The Company believes the value of the Settlement Agreements is equal to the net present value of the litigated Further Restated and Amended Coal Supply Agreement.

New Restated and Amended Coal Supply Agreement: Effective January 1, 2001, the parties agreed to terminate the Further Restated and Amended Coal Supply Agreement, and replace it with the New Restated and Amended Coal Supply Agreement (New Agreement). The New Agreement began on January 1, 2001, and extends to December 31, 2022. Under the New Agreement, the Company received an extension of sales beyond the June 8, 2013 term of the former Coal Supply Agreement. PacifiCorp will receive a price reduction for each ton of coal purchased. The minimum purchase obligation under the New Agreement increased to 1,500,000 tons of coal for each calendar year of the contract term, subject to adjustment for planned outages. The New Agreement further provided for a special one-time payment by PacifiCorp in the amount of $7.3 million, which was received in August 2001. This payment primarily related to disputed billings under the previous agreement and a value transfer premium. Of this payment, $5.6 million was recognized currently and is included in "Other, net" non-operating income on the accompanying Consolidated Statements of Income, $1.0 million was previously recognized in revenues and the remaining $0.7 million is being recognized as sales are made under the New Agreement.

Coal Option Agreement: The term of this agreement began October 1, 2001, and extends until December 31, 2010. The agreement provides that PacifiCorp shall purchase 1,400,000 tons of coal during the period of October 1, 2001 through December 31, 2002 and 1,000,000 tons of coal in 2003 at a fixed price. The agreement further provides the Company with a "put" option for 2002 and 2003 under which the Company may sell to PacifiCorp up to 500,000 tons of coal from the Wyodak Mine at a market based price. For each calendar year from January 1, 2004 through 2010, the put option is increased to a maximum of 1,000,000 tons at a market based price. The "put" tonnages will be reduced or offset for quantities of an enhanced coal known as "K-Fuel" purchased by PacifiCorp under the KFx Facility Output Agreement. Additionally, for each calendar year during which the Company is selling to PacifiCorp K-Fuel under the KFx Facility Output Agreement described below, and in which the Company has not exercised its "put" option, PacifiCorp may elect to purchase an equal amount of tonnage from the Company's coal reserves to use in a 50/50 blend with the K-Fuel, up to 500,000 tons per year in 2002 through 2007 at a market based price with a fixed floor.

Asset Option Agreement: This agreement provides PacifiCorp an option to purchase a 10 percent interest in the KFx facility or the legal entity that owns the KFx facility at a market based price.

Sale of North Conveyor System: The Company sold the "North Conveyor System" to PacifiCorp, which served as the backup coal delivery system for the Wyodak Power Plant which resulted in a $2.6 million gain that is included in "Other, net" non-operating income on the accompanying Consolidated Statements of Income.

KFx Facility Output Agreement: The KFx plant is a coal enhancement facility the Company owns located near its Wyodak Coal Mine. The KFx plant was built to produce an enhanced coal known as "K-Fuel." Assuming the plant becomes operational, PacifiCorp agrees to purchase K-Fuel for a term beginning January 1, 2002, and extending to December 31, 2007. If the plant is not operational on or before December 31, 2003, the agreement will become void. Under this agreement, PacifiCorp agrees to purchase the output of K-Fuel from the KFx plant, up to a maximum of 500,000 tons for each calendar year from 2002 through 2007 at fixed price with market based escalation. Wyodak reserves the right to sell up to a total of 100,000 tons from the output of the KFx plant to other customers during the same time period.

Ongoing Litigation

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 the Company and those of the following subsidiaries, 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:

	2001	2000	1999
	(in thousands)		
Service cost	$ 945	$ 967	$ 1,174
Interest cost	3,080	2,885	2,598
Estimated return on assets	(5,814)	(5,257)	(4,162)
Amortization of transition amount	-	(90)	(90)
Amortization of prior service cost	231	231	89
Recognized net actuarial gain	(556)	(537)	-
Net pension income	$(2,114)	$(1,801)	$ (391)
Actuarial assumptions:			
Discount rate	7.5%	7.5%	6.75%
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%

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*The rate of increase in compensation levels for 2001 was changed from a single rate assumption for all ages to an age-based salary scale assumption resulting in a weighted average increase of 5.0 percent.

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

	2001	2000
	(in thousands)	
Beginning projected benefit obligation	$41,314	$39,615
Service cost	945	967
Interest cost	3,080	2,885
Actuarial gains	(167)	(48)
Benefits paid	(2,156)	(2,105)
Net increase	1,702	1,699
Ending projected benefit obligation	$43,016	$41,314

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

	2001	2000
	(in thousands)	
Beginning market value of plan assets	$56,560	$51,212
Benefits paid	(2,156)	(2,105)
Investment income (loss)	(13,136)	7,453
Ending market value of plan assets	$41,268	$56,560

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

	2001	2000
	(in thousands)	
Fair value of plan assets	$41,268	$56,560
Projected benefit obligation	(43,016)	(41,314)
Funded status	(1,748)	15,246
Unrecognized:		
Net (gain) loss	5,527	(13,812)
Prior service cost	1,823	2,054
Prepaid pension cost	$ 5,602	$ 3,488
Accumulated benefit obligation	$35,695	$33,374

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 during 2001 and 2000 and $0.4 million during 1999.

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:

	2001	2000	1999
		(in thousands)	
Service cost	$ 289	$ 282	$225
Interest cost	507	523	362
Amortization of transition obligation	150	150	150
Loss	21	68	1
	$ 967	$1,023	$738

Funding information as of October 1 was as follows:

	2001	2000
	(in thousands)	
Accumulated postretirement benefit obligation:		
Retirees	$3,186	$2,478
Fully eligible active participants	1,803	1,203
Other active participants	3,963	3,172
Unfunded accumulated postretirement benefit obligation	8,952	6,853
Unrecognized net loss	(2,792)	(1,001)
Unrecognized transition obligation	(1,648)	(1,797)
Accrued postretirement cost	$4,512	$4,055

For measurement purposes, an 8.0 percent annual rate of increase in healthcare benefits was assumed for 2001; the rate was assumed to decrease gradually to 6.0 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 23.8 percent and the net periodic postretirement cost $0.3 million or 28.1 percent. A one percent decrease would reduce the service and interest cost by $0.1 million or 18.3 percent and decrease the net periodic postretirement cost $0.2 million or 17.2 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 $0.9 million for 2001 and $0.6 million for 2000.

(12) OTHER COMPREHENSIVE INCOME

The following table displays the related tax effects allocated to each component of Other Comprehensive Income (Loss) for the year ended December 31, 2001:

	Pre-tax Amount	Tax Expense (Benefit)	Net-of-tax Amount
		(in thousands)	
Unrealized gain on securities during the year	$ 1,775	$ 337	$ 1,438
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of $2,875)	(7,299)	(2,932)	(4,367)
Other comprehensive loss	$(5,524)	$(2,595)	$(2,929)

Items of other comprehensive income (loss) were not significant in 2000 or 1999.

(13) INCOME TAXES

Income tax expense for the years indicated was:

	2001	2000	1999
		(in thousands)	
Current:			
Federal	$38,372	$27,122	$13,662
State	1,986	1,283	266
	40,358	28,405	13,928
Deferred	10,224	2,576	2,931
Tax credits	(432)	(639)	(640)
	$50,150	$30,342	$16,219

The temporary differences, which gave rise to the net deferred tax liability, were as follows:

Years ended December 31,	2001	2000
	(in thousands)	
Deferred tax assets:		
Accelerated depreciation, amortization and other plant-related differences	$ 647	$ 5,393
Regulatory asset	2,169	2,507
Valuation reserves	3,057	508
Mining development and oil exploration	1,501	3,605
Employee benefits	4,168	3,308
Items of other comprehensive income	4,540	-
Other	6,176	3,203
	22,258	18,524
Deferred tax liabilities:		
Accelerated depreciation and other plant-related differences	74,449	63,559
Regulatory liability	1,425	1,447
Mining development and oil exploration	8,650	8,450
Employee benefits	2,152	1,347
Derivative fair value adjustments	1,776	-
Items of other comprehensive income	1,945	-
Other	7,163	6,400
	97,560	81,203
Net deferred tax liability	$75,302	$62,679

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

	2001	2000	1999
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	1.4	1.5	0.5
Amortization of investment tax credits	(0.3)	(0.8)	(1.2)
Percentage depletion in excess of cost	(0.8)	(1.1)	(1.6)
Other	1.1	1.9	(2.6)
	36.4%	36.5%	30.1%

(14) 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, 2001, 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; Integrated 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 natural gas interests located in the Rocky Mountain region, Texas, California and other states; Energy Marketing, which markets natural gas, oil and related services to customers in the Midwest, Southwest, Rocky Mountain, West Coast and Northwest regions markets; Power Generation, which produces and sells power to wholesale customers; and Communications, which primarily markets communications and software development services.

December 31:	2001	2000
	(in thousands)	
Total assets		
Integrated energy:		
Coal mining	$ 42,198	$ 47,038
Oil and gas	57,766	36,376
Energy marketing	134,496	328,960
Power generation	867,203	375,801
Electric utility	421,280	412,213
Communications	123,634	106,884
Corporate	2,100	1,039
Discontinued operations	10,090	12,009
Total assets	$1,658,767	$1,320,320
Capital expenditures and acquisitions		
Integrated energy:		
Coal mining	$ 7,855	$ 2,419
Oil and gas	27,114	9,259
Energy marketing	152	273
Power generation	497,653	76,932*
Electric utility	41,313	25,257
Communications	20,030	59,377
Corporate	25	-
Total capital expenditures and acquisitions	$ 594,142	$ 173,517

*Excludes the non-cash acquisition of Indeck Capital, Inc. as described in Note 15.

Property, plant and equipment		
Integrated energy:		
Coal mining	$ 63,592	$ 57,720
Oil and gas	104,926	77,812
Energy marketing	660	1,443
Power generation	696,345	294,805
Electric utility	569,368	530,380
Communications	129,748	109,718
Corporate	25	135
Total property, plant and equipment	$1,564,664	$1,072,013

December 31:	2001	2000	1999
		(in thousands)	
External operating revenues			
Integrated energy:			
Coal mining	$ 20,551	$ 20,880	$ 23,431
Oil and gas	33,408	20,328	13,052
Energy marketing (a)	83,884	40,204	7,640
Power generation	80,233	20,083	-
Electric utility	212,355	173,308	133,222
Communications	20,258	7,689	278
Total external operating revenues	$ 450,689	$ 282,492	$177,623
Intersegment operating revenues			
Integrated energy:			
Coal mining	$ 11,249	$ 9,650	$ 7,664
Communications	4,250	3,682	3,145
Intersegment eliminations	(4,250)	(3,682)	(3,145)
Total intersegment operating revenues(b)	$ 11,249	$ 9,650	$ 7,664

(a) Operating revenues presented for energy marketing represent trading margins.

(b) In accordance with the provisions of SFAS 71, intercompany fuel sales to the electric utility segment are not eliminated.

December 31:	2001	2000	1999
Depreciation, depletion and amortization			
Integrated energy:			
Coal mining	$ 2,984	$ 3,525	$ 3,259
Oil and gas	7,806	4,071	2,953
Energy marketing	484	404	2,517
Power generation	16,520	3,646	-
Electric utility	15,773	14,966	15,552
Communications	9,944	6,012	546
Corporate	300	-	-
Depreciation, depletion and amortization	$ 53,811	$ 32,624	$ 24,827
Operating income (loss)			
Integrated energy:			
Coal mining	$ 6,586	$ 8,795	$12,606
Oil and gas	15,193	7,906	3,978
Energy marketing	53,662	24,113	(1,366)
Power generation	27,455	20,374	(157)
Electric utility	84,108	68,208	52,286
Communications	(13,250)	(12,486)	(3,647)
Corporate	(3,984)	(1,821)	(926)
Total operating income	$ 169,770	$115,089	$62,774

December 31:	2001	2000	1999
		(in thousands)	
Interest income			
Integrated energy:			
Coal mining	$ 8,125	$ 9,974	$ 2,709
Oil and gas	45	39	18
Energy marketing	1,854	527	330
Power generation	8,991	4,085	101
Electric utility	4,858	5,658	1,190
Communications	15	657	1,050
Corporate	7,379	369	399
Intersegment eliminations	(28,895)	(14,242)	(2,200)
Total interest income	$ 2,372	$ 7,067	$ 3,597
Interest expense			
Integrated energy:			
Coal mining	$ 5,752	$ 8,006	$ 1,259
Oil and gas	145	372	568
Energy marketing	17	329	486
Power generation	33,593	11,911	111
Electric utility	15,780	17,411	13,830
Communications	5,789	6,244	1,155
Corporate	7,298	105	17
Intersegment eliminations	(28,895)	(14,242)	(2,200)
Total interest expense	$ 39,479	$ 30,136	$ 15,226
Income taxes			
Integrated energy:			
Coal mining	$ 6,266	$ 2,660	$ 3,439
Oil and gas	4,930	2,609	968
Energy marketing	20,933	9,308	480
Power generation	1,668	3,154	(58)
Electric utility	24,255	19,469	12,446
Communications	(6,561)	(6,477)	(807)
Corporate	(1,341)	(381)	(249)
Total income taxes	$ 50,150	$ 30,342	$ 16,219
Net income (loss) from continuing operations			
Integrated energy:			
Coal mining	$ 11,591	$ 7,172	$ 9,714
Oil and gas	10,197	4,992	2,462
Energy marketing	34,566	13,973	486
Power generation	1,576	3,242	(108)
Electric utility	45,238	37,178	27,362
Communications	(12,300)	(11,382)	(968)
Corporate	(2,560)	(1,175)	(295)
Intersegment eliminations	(724)	(1,188)	(915)
Total net income from continuing operations	$ 87,584	$ 52,812	$ 37,738

(15) ACQUISITIONS

On April 11, 2001, the Company's power generation subsidiary, Black Hills Energy Capital, purchased the Fountain Valley facility, a 240 megawatt generation facility located near Colorado Springs, Colorado, featuring six LM-6000 simple-cycle, gas-fired turbines. The facility came on-line mid third quarter of 2001. The facility was purchased from Enron Corporation. Total cost of the project was approximately $183 million and has been financed primarily with non-recourse project debt. The Company has obtained an 11-year contract with Public Service of Colorado to utilize the facility for peaking purposes. The contract is a tolling arrangement in which the Company assumes no fuel risk. The transaction has been accounted for as an asset purchase recorded at cost.

On August 31, 2001, Black Hills Energy Capital purchased a 277 megawatt gas-fired co-generation power plant project located in North Las Vegas, Nevada from Enron North America, a wholly owned subsidiary of Enron Corporation. The facility currently has a 53 megawatt co-generation power plant in operation. Most of the power from that facility is under a long-term contract expiring in 2024. The Company has sold 50 percent of this power plant to other parties; however, under generally accepted accounting principles the Company is required to consolidate 100 percent of this plant. The project also has a 224 megawatt combined-cycle expansion under way, which is 100 percent owned by the Company. The facility is scheduled to be operational in the fourth quarter of 2002 and will utilize LM-6000 technology. The power of the expansion is also under a long-term contract, which expires in 2017. This contract for the expansion requires the purchaser to provide fuel to the power plant when it is dispatched. Total construction and acquisition cost for the entire facility is expected to be approximately $330 million of which $302 million was expended as of September 30, 2002.

The acquisition has been accounted for under the purchase method of accounting and, accordingly, the purchase price of approximately $205 million has been allocated to the acquired assets and liabilities based on preliminary 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 $150 million (excluding goodwill and other intangibles) and liabilities assumed of approximately $2.0 million. The purchase price and related acquisition costs exceeded the fair values assigned to net tangible assets by approximately $57.0 million, which was recorded as long-lived intangible assets and goodwill.

In addition, during 2001, the Company acquired an additional 31 percent interest and a 13 percent interest in its consolidated majority-owned subsidiaries, Black Hills North American Power Fund, L.P. and Indeck North American Power Partners, L.P., respectively, from minority shareholders. Total consideration paid was $15.9 million.

Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not significant to the Company's financial position or results of operations.

On July 7, 2000, the Company acquired Indeck Capital, Inc. and merged it into its subsidiary, Black Hills Energy Capital, Inc. 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, along with $4.0 million in preferred stock, resulting in a purchase price of $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 beginning in 2000. As of December 31, 2001, $3.6 million has been paid under the earn-out. The earn-out consideration is 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 is recorded as an increase to goodwill.

The acquisition was accounted for under the purchase method of accounting and, accordingly, the purchase price was 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 $151.1 million (excluding goodwill) and liabilities assumed of $138.7 million. The purchase price and related acquisition costs exceeded the fair values assigned to net tangible assets by $25.4 million, which was recorded as goodwill and was being amortized over 25 years on a straight-line basis during 2001 and 2000.

In addition during 2000, 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 $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 $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 $12.9 million in cash.

(16) OIL AND GAS RESERVES (Unaudited)

Black Hills Exploration and Production has interests in 813 producing oil and gas properties in nine states. Black Hills Exploration and Production also holds leases on approximately 228,551 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 year-end product prices, as of December 31, 2001, 2000 and 1999, 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.

	2001		2000		1999	
	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	4,413	18,404	4,109	19,460	2,368	15,952
Production	(446)	(4,615)	(352)	(3,285)	(309)	(2,801)
Additions	749	19,111	625	4,228	376	7,718
Property sales	-	-	-	-	(164)	(66)
Revisions to previous estimates	(661)	(8,829)	31	(1,999)	1,838	(1,343)
Balance at end of year	4,055	24,071	4,413	18,404	4,109	19,460
Proved developed reserves at end of year included above	2,962	22,420	3,047	16,418	2,819	14,391
Year-end prices (average well-head)	$18.12	$ 2.05	$26.76	$ 8.05	$25.60	$ 1.99

(17) 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 2001 and 2000.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
2001				
Operating revenues	$142,301	$130,442	$95,124	$94,071
Operating income	60,711	63,651	30,817	14,591
Income from continuing operations	31,436	34,528	17,005	4,615
Income from discontinued operations	655	325	(638)	151
Net income	32,091	34,853	16,367	4,766
Net income available for common stock	32,050	34,553	16,235	4,712
Earnings per common share:				
Basic -				
Continuing operations	1.36	1.34	0.64	0.17
Discontinued operations	0.03	0.01	(0.03)	0.01
Total	1.39	1.35	0.61	0.18
Diluted -				
Continuing operations	1.34	1.33	0.63	0.17
Discontinued operations	0.03	0.01	(0.02)	0.01
Total	1.37	1.34	0.61	0.18
Dividends paid per share	0.28	0.28	0.28	0.28
Common stock prices				
High	45.74	58.50	45.55	34.20
Low	31.00	39.50	27.76	26.00

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
2000				
Operating revenues	$48,352	$50,571	$81,228	$111,991
Operating income	16,992	15,669	43,037	39,391
Income from continuing operations	9,187	8,363	16,365	18,897
Income from discontinued operations	(126)	(302)	(43)	507
Net income	9,061	8,061	16,322	19,404
Net income available for common stock	9,061	8,061	16,285	19,363
Earnings per common share:				
Basic -				
Continuing operations	0.43	0.39	0.72	0.82
Discontinued operations	(0.01)	(0.01)	(0.01)	0.02
Total	0.42	0.38	0.71	0.84
Diluted -				
Continuing operations	0.43	0.39	0.71	0.81
Discontinued operations	(0.01)	(0.01)	-	0.02
Total	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

(18) SUBSEQUENT EVENTS

Discontinued Operations

During the second quarter of 2002, the Company adopted a plan to dispose of its coal marketing subsidiary, Black Hills Coal Network. The sale and disposal was finalized in July 2002. In connection with the plan of disposal, the Company determined that the carrying values of some of the underlying assets exceeded their fair values and a charge to operations was required. The Company recorded an after tax charge of approximately $1.0 million, which represents the difference between the carrying value of the assets and liabilities of the subsidiary versus its fair value, less cost to sell. Results of operations and the related charges have been classified as "Discontinued operations" in the accompanying Consolidated Statements of Income, and prior periods have been restated. For business segment reporting purposes, the coal marketing business results were previously included in the segment "Energy Marketing."

Revenues and net income from the discontinued operations are as follows:

	2001	2000	1999
		(in thousands)	
Revenues	$ 3,660	$ 1,578	$ 1,111
Pre-tax income (loss) from discontinued operations	886	52	(1,101)
Income tax benefit (expense)	(393)	(16)	430
Net income (loss) from discontinued operations	$ 493	$ 36	$ (671)

Assets and liabilities of the discontinued operations are as follows:

	2001	2000
	(in thousands)	
Current assets	$ 7,878	$ 10,287
Non-current assets	2,212	1,722
Current liabilities	(8,724)	(11,080)
Non-current liabilities	(96)	-
Net assets (liabilities) of discontinued operations	$ 1,270	$ 929

Energy Trading Activities

During June 2002, the Emerging Issues Task Force (EITF) reached a consensus on Issues 1 and 3 of EITF Issue No. 02-3, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issue No. 98-10," "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," and No. 00-17, "Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10."

At a meeting on October 25, 2002, the EITF reached new consensuses that effectively supersede the consensus on EITF 02-3, reached at its June 2002 meeting. At its October 2002 meeting, the EITF reached a consensus to rescind EITF 98-10, the impact of which is to preclude mark-to-market accounting for all energy trading contracts not within the scope of FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities." The EITF also reached a consensus that gains and losses on derivative instruments within the scope of Statement 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. The consensus regarding the rescission of Issue 98-10 is applicable for fiscal periods beginning after December 15, 2002. Energy trading contracts not within the scope of Statement 133 entered into after October 25,2002, but prior to the implementation of the consensus are not permitted to apply mark-to-market accounting. The Company has not yet quantified the financial statement effect of this EITF action. The Company currently reports its energy trading activities on a net basis.

Acquisitions of Additional Interests

On March 8, 2002, the Company acquired an additional 67 percent ownership interest in Millennium Pipeline Company, L.P., which owns and operates a 200-mile pipeline. The pipeline has a capacity of approximately 65,000 barrels of oil per day, and transports imported crude oil from Beaumont, Texas to Longview, Texas, which is the transfer point to connecting carriers. The Company also acquired additional ownership interest in Millennium Terminal Company, L.P., which has 1.1 million barrels of crude oil storage connected to the Millennium Pipeline at the Oil Tanking terminal in Beaumont. The Millennium system is presently operating near capacity through shipper agreements. These acquisitions give the Company 100 percent ownership in the Millennium companies. Total cost of the acquisitions was $11.0 million and was funded through borrowings under short-term revolving credit facilities.

On March 15, 2002, the Company paid $25.7 million to acquire an additional 30 percent interest in the Harbor Cogeneration Facility (the Facility), a 98-megawatt gas-fired plant located in Wilmington, California. The acquisition was funded through borrowings under short-term revolving credit facilities and gives the Company an 83 percent ownership interest and voting control of the Facility.

The Company's investments in the above entities prior to the above acquisitions were accounted for under the equity method of accounting and were included in Investments on the accompanying Consolidated Balance Sheets. Each of the above acquisitions gave the Company majority ownership and voting control of the respective entities, therefore, after acquisition the Company will consolidate each of the entities in its consolidated financial statements.

The above acquisitions have been accounted for under the purchase method of accounting and, accordingly, the purchase prices have been allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and the liabilities assumed as of the date of acquisition. The estimated purchase price allocations are subject to adjustment, generally within one year of the date of acquisition. The purchase prices and related acquisition costs exceeded the fair values assigned to net intangible assets by approximately $9.3 million, which was recorded as long-lived intangible assets.

The impact of these acquisitions was not material in relation to the Company's results of operations. Consequently, pro forma information is not presented.

Other Acquisitions

During July 2002, the Company purchased the assets of the Kilgore to Houston Pipeline System from Equilon Pipeline Company, LLC. The Kilgore pipeline transports crude oil from the Kilgore, Texas region south to Houston, Texas, which is the transfer point to connecting carriers via the Oil Tanking Houston terminal facilities. The 10-inch pipeline is approximately 190 miles long and has a capacity of up to approximately 35,000 barrels per day. In addition, the Kilgore system has approximately 400,000 barrels of crude oil storage at Kilgore and 375,000 barrels of storage at the Texoma Tank Farm located in Longview, Texas. Total cost of the acquisition was $6.7 million and was funded through borrowings under short-term credit facilities.

Potential Acquisition - unaudited

On October 1, 2002, the Company entered into a definitive merger agreement to acquire Denver-based Mallon Resources Corporation. Total cost of the acquisition is estimated to be $52 million, which includes the Company's acquisition on October 1, 2002 of Mallon's debt to Aquila Energy Capital Corporation and the settlement of outstanding hedges, amounting to $30.5 million. The merger agreement, which has been approved by both companies' Board of Directors, provides that Mallon shareholders will receive 0.044 of a share of Black Hills for each share of Mallon. Completion of the acquisition which is subject to customary conditions, including the approval by the shareholders of Mallon, is expected in the first quarter of 2003.

Mallon Resources' proved reserves, as reported at December 31, 2001, were 53.3 billion cubic feet of gas equivalent. The Company estimates that Mallon's current proved reserves could be substantially higher based on its review of the reserves and current oil and gas prices. The reserves are located primarily on the Jicarilla Apache Nation in the San Juan Basin of New Mexico and are comprised almost entirely of natural gas in shallow sand formations. The oil and gas leases of the acquisition total more than 66,500 gross acres (56,000 net), most of which is contained in a contiguous block that is in the early stages of development.

Current daily net production of the Mallon properties is nearly 13 million cubic feet of gas equivalent. Mallon operates 149 of 171 total gas and oil wells, with working interests averaging 90 to 100 percent in most of the wells and undeveloped acreage.

Upon closing, the Company expects the acquisition to increase gas and oil production immediately by approximately 60 percent and more than double the Company's proven oil and gas reserves. After the acquisition is closed, the Company plans to initiate an expanded development and exploratory drilling program on the properties which is expected to increase gas production, reserves and cash flow from fuel operations in late 2003 and beyond. The acquisition is expected to have a nominal earnings-per-share impact until production levels can be increased.

Financings

On March 14, 2002, the Company closed on $135 million five-year senior secured project-level financing for the Arapahoe and Valmont facilities. These projects have a total of 210-megawatts in service and are located in the Denver, Colorado area. Proceeds from this financing were used to refinance $53.8 million of an existing seven-year secured term project-level facility, pay down approximately $50 million of short-term credit facility borrowings and approximately $31.2 million was used for project construction. At September 30, 2002, all of the $135 million financing had been utilized.

During the first quarter of 2002, the Company completed a $50 million bridge credit agreement. The credit agreement supplemented the Company's revolving credit facilities and had the same terms as those facilities with an original expiration date of June 30, 2002, which was subsequently extended to September 27, 2002. On September 27, 2002, this $50 million facility was replaced by a $50 million secured financing for the expansion at our Las Vegas II project, a 224-megawatt gas-fired generation facility located in North Las Vegas, Nevada which expires on November 26, 2002. The financing is guaranteed by the Company.

On June 18, 2002, the Company closed on a $75 million bridge credit agreement. The credit agreement bridged the issuance of $75 million of Black Hills Power First Mortgage Bonds, which were issued on August 13, 2002. The termination date of the bridge credit agreement was August 13, 2002, the date on which the First Mortgage Bonds were issued.

On June 28, 2002, the Company's gas marketing subsidiary, Enserco Energy, Inc. closed on a $135 million uncommitted, discretionary credit facility, which became effective July 1, 2002 and expires June 27, 2003. This facility replaced the prior $75 million Enserco Energy facility.

On August 13, 2002, The Company's electric utility subsidiary, Black Hills Power, Inc., issued $75 million of First Mortgage Bonds, Series AE, due 2032. The First Mortgage Bonds have a 7.23 percent coupon with interest payable semiannually, commencing February 15, 2003. Net proceeds from the offering were and will be used to fund the Company's portion of construction and installation costs for an AC-DC-AC Converter Station; for general capital expenditures for the remainder of 2002 and 2003; to repay a portion of current bank indebtedness; to satisfy bond maturities for certain outstanding first mortgage bonds due in 2003; and for general corporate purposes.

In August 2002, the Company closed on a $195 million unsecured revolving credit facility that expires August 26, 2003. The credit facility extended the Company's previous $200 million 364-day credit facility that expired on August 27, 2002.

On September 25, 2002, the Company closed on a $35 million two-year unsecured credit agreement. Proceeds were used to fund the Company's working capital needs and for general corporate purposes.

The $195 million credit facility, the $200 million three-year credit facility and the $35 million two-year credit facility contain a liquidity covenant that requires the Company to have $30 million in liquid assets as of the last day of each fiscal quarter beginning with December 31, 2002. Liquid assets are defined as unrestricted cash and available unused capacity under capacity under the Company's credit facilities.

Exhibit No.	Description
23.1	Independent Auditors' Consent
23.2	Consent of Petroleum Engineer and Geologist
99.1	Press release dated November 25, 2002 issued by Black Hills Corporation

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

BLACK HILLS CORPORATION

By: /s/ Mark T. Thies

Mark T. Thies
Sr. Vice President
and Chief Financial Officer

Date: November 25, 2002

Exhibit Index

Exhibit Number	Description
23.1	Independent Auditors' Consent
23.2	Consent of Petroleum Engineer and Geologist
99.1	Press release dated November 25, 2002 issued by Black Hills Corporation

Exhibit 23.1

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statements No. 33-71130 of Black Hills Corporation on Form S-3 and Registration Nos. 33-63059, 333-17451, 333-61969, 333-30272 and 333-63264 of Black Hills Corporation on Form S-8 of our report dated November 15, 2002 (which expresses an unqualified opinion and includes an emphasis of the matter paragraph relating to the adoption of Statement of Financial Accounting Standard No. 133) on Black Hills Corporation as of December 31, 2001 and 2000 and for the three years in the period ended December 31, 2001, appearing in this Form 8-K.

DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
November 25, 2002

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 8-K with respect to the oil and gas reserves of Black Hills Exploration and Production, Inc., the future net revenues from such reserves, and the present value thereof, which information has been included in this Form 8-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 8-K and to the incorporation by reference in the Registration Statements on Form S-8 Nos. 33-63059, 333-61969, 333-17451, 333-82787, 333-30272 and 333-63264 and the Registration Statement on Form S-3, No. 33-71130.

RALPH E. DAVIS ASSOCIATES, INC.

/s/ Joseph Mustacchia, Jr.

Joseph Mustacchia, Jr.
Executive Vice President

November 21, 2002

Exhibit 99.1

BLACK HILLS CORPORATION REISSUES FINANCIAL STATEMENTS

- Deloitte & Touche Completes Re-audit

RAPID CITY, SD--November 25, 2002--Black Hills Corporation (NYSE: BKH) announced today that its new independent public accountants, Deloitte & Touche LLP, have completed the audit of Black Hills Corporation's 2001, 2000 and 1999 financial statements that were originally audited by Arthur Andersen LLP. The reissued financial statements, including the report of Deloitte & Touche, were submitted to the Securities and Exchange Commission in a Form 8-K filed today. The net income and earnings per share in the reissued financial statements are unchanged from amounts previously reported in its 2001 Form 10-K.

Because Black Hills Corporation is reissuing the financial statements as of a current date, three areas of the reissued financial statements being filed today differ from Black Hills Corporation's 2001 Annual Report on Form 10-K as previously filed:

- Discontinued operations presentation in the financial statements for the disposition of Black Hills Coal Network;

- Reporting of energy trading results on a net basis; and

- Disclosure of various subsequent events occurring since the 2001 financial statements were previously issued.

The discontinued operations disclosures and presentation changes in the reissued financial statements relate to Black Hills Corporation's second quarter 2002 plan to dispose of its coal marketing subsidiary, Black Hills Coal Network, Inc., and the completion of the sale in July 2002. Securities and Exchange Commission (SEC) rules require that once operations are reported as discontinued (as they were in Black Hills Corporation's second and third quarter Form 10-Qs for 2002), subsequent financial statements must present such operations on a consistent basis. Discontinued operations disclosures have been added in a new footnote to Black Hills Corporation's reissued financial statements.

The trading reclassifications relate to new reporting requirements issued in 2002 by the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board. The EITF's decision requires that beginning in 2003 trading revenues and expenses be presented on a net basis. Black Hills elected to reclassify trading costs of approximately $1.0 billion, $1.3 billion and $0.6 billion in 2001, 2000 and 1999, respectively, against trading revenues to present net trading margins in Black Hills Corporation's reissued income statements.

Given the current release of the reissued financial statements, reporting rules require that certain subsequent events in 2002 be disclosed to the extent they are relevant to the 2001, 2000 and 1999 financial statements. The reissued Black Hills Corporation financial statements include updated disclosures of various events in 2002.

The disclosure and presentation changes did not affect net income or earnings per share from amounts previously reported for Black Hills Corporation. Also, total assets, liabilities and shareholders' equity remain unchanged in the reissued financial statements from amounts previously reported for Black Hills Corporation. The discontinued operations and the trading reclassifications, however, did reduce total revenues of Black Hills Corporation from amounts previously reported and did reclassify other items on the income statements and balance sheets.

Black Hills Corporation (www.blackhillscorp.com) is a diverse energy and communications company with three business groups: Black Hills Energy, the integrated energy unit which generates electricity, produces natural gas, oil and coal and markets energy; Black Hills Power, an electric utility serving western South Dakota, northeastern Wyoming and southeastern Montana; and Black Hills FiberCom, a broadband communications company offering bundled telephone, high speed Internet and cable entertainment services.