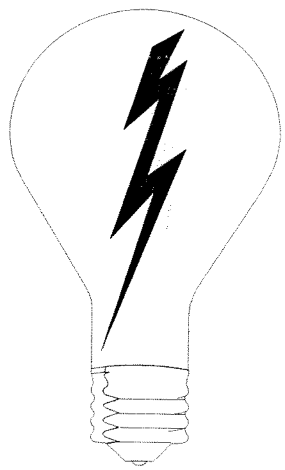
YEAR ENDING 2003

ANNUAL REPORT
OF
Black Hills Corporation

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

REVISED JULY 28, 1998

Company Name: Black Hills Power, Inc. SCHEDULE 1

IDENTIFICATION

Year: **2003**

1.	Legal Name of Respondent:	Black Hills Power, Inc.
2.	Name Under Which Respondent Does Business:	Black Hills Power, Inc.
3.	Date Utility Service First Offered in Montana	2/23/1968
4.	Address to send Correspondence Concerning Report:	Mark T. Thies 625 Ninth Street Rapid City, SD 57701
5.	Person Responsible for This Report:	Mark T. Thies Exec. V.P. & CFO
5a.	Telephone Number:	605-721-1700

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

1a. Name and address of the controlling organization or person:	Black Hills Corporation
1b. Means by which control was held:	Common Stock
1c. Percent Ownership:	100%

SCHEDULE 2

Board of Directors

Line No.	Name of Director and Address (City, State) (a)		Remuneration (b)
1	Bruce B. Brundage	Larkspur, CO	52,000
2	Thomas J. Zeller	Rapid City, SD	54,000
3	Adil M. Ameer (c)	Rapid City, SD	19,324
4	John R. Howard	Rapid City, SD	82,000
5	Everett E. Hoyt (a)	Rapid City, SD	
6	Kay S. Jorgensen	Spearfish, SD	48,000
7	Daniel P. Landguth (a)	Rapid City, SD	
8	David C. Ebertz	Gillette, WY	51,000
9	David S. Maney(b)	Lakewood, CO	47,000
10	Steven J. Helmers(a) (d)	Rapid City, SD	
11	Richard Korpan(f)	Evergreen, CO	21,000
12	David R. Emery(a) (e)	Rapid City, SD	
13	Stephen D. Newlin	Medina, MN	
14			
15	(a) Officers of the Company -		
16	Not compensated as Directors		
17			
18	(b) Resigned from the Board of Directors January 9, 2004.		
19			
20	(c) Resigned from the Board of Directors March 27, 2003		
21			
22	(d) Resigned from the Board of Directors June 2, 2003		
23			
24	(e) Elected to the Board of Directors January 9, 2004		
25			
26	(f) Elected to the Board of Directors June 2, 2003		
27			

Chart One

OCTOBER 20, 2003

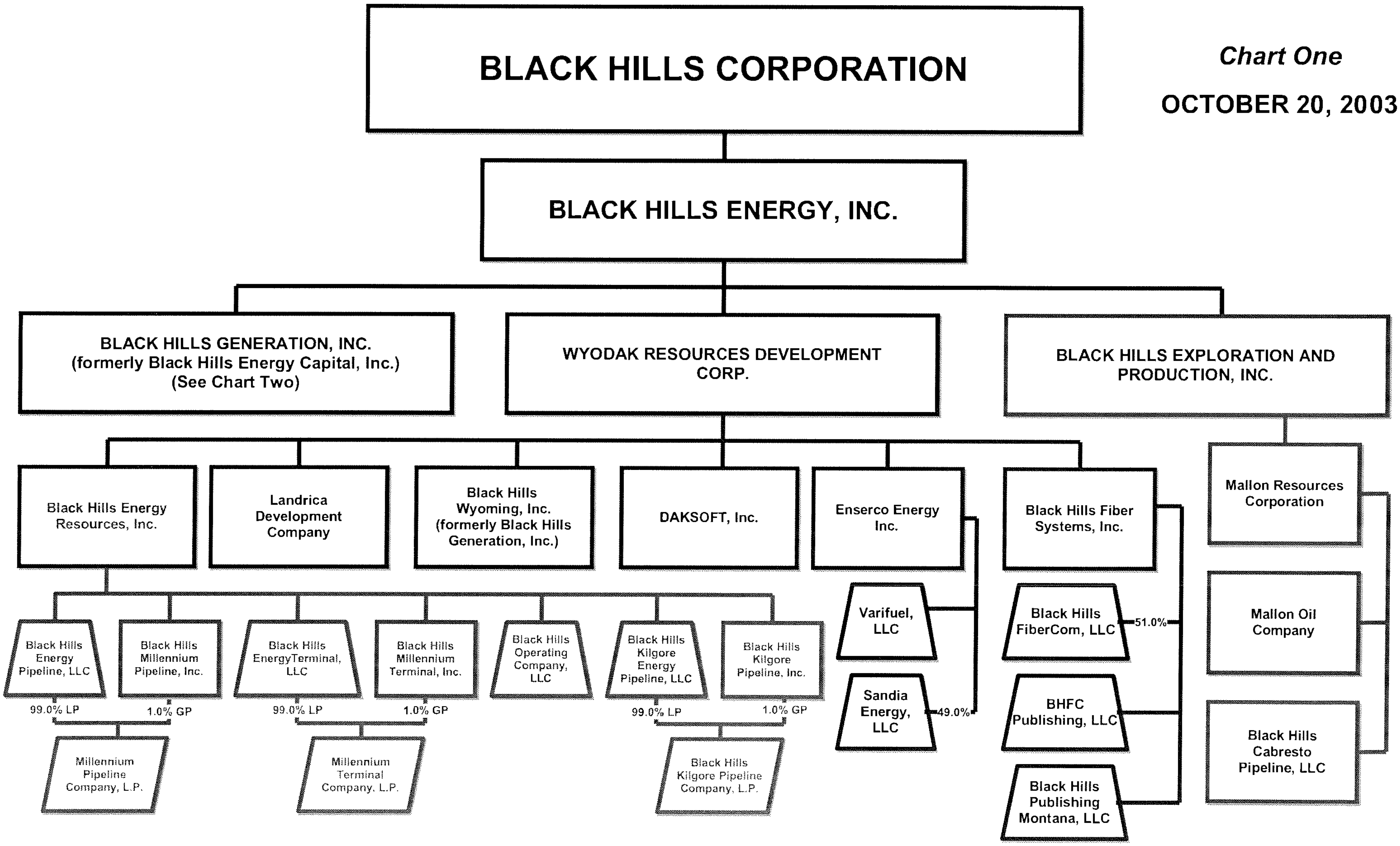
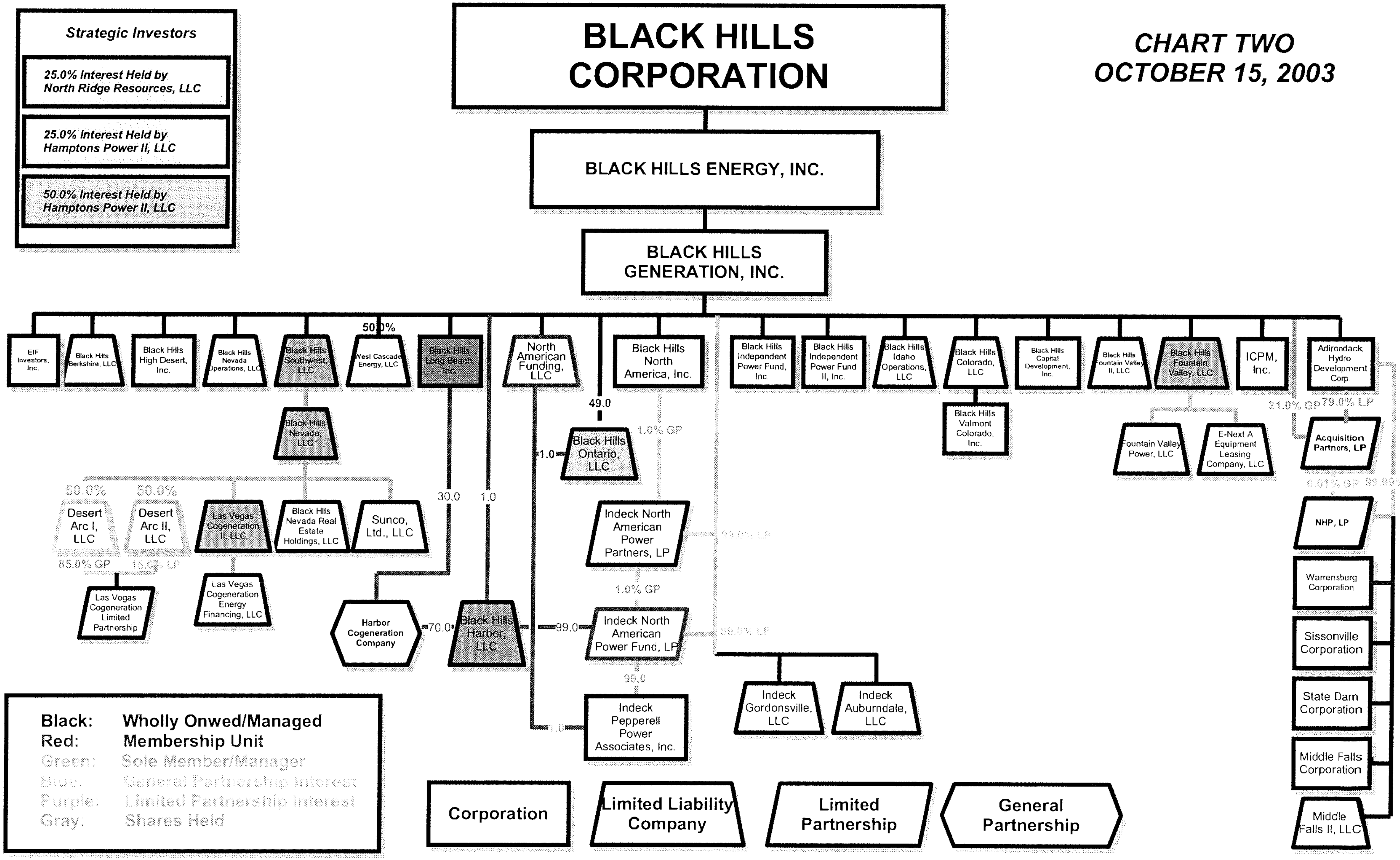


CHART TWO
OCTOBER 15, 2003



Officers

Year: 2003

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman		Daniel P. Landguth
2			
3	Vice-Chairman		Everett E. Hoyt
4			
5	President & Chief Executive Officer		David R. Emery
6			
7	Executive Vice President, CFO,		Mark T. Thies
8	Assistant Treasurer &		
9	Assistant Secretary		
10			
11	Sr. Vice President -		James M. Mattern
12	Corporate Administration and		
13	Compliance		
14			
15	Sr. Vice President - General Counsel		Steven J. Helmers
16			
17	Sr. Vice President and Chief Risk Officer		Russell L. Cohen
18			
19	Vice President Governance and		Roxann R. Basham
20	Corporate Secretary		
21			
22	Vice President and Treasurer		Garner Anderson
23			
24	Vice President - Corporate Affairs		Kyle D. White
25			
26	Vice President and General Manager		Stuart Wevik
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CORPORATE STRUCTURE

Year: 2003

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	24,089,283	92.67%
2	Black Hills Generation, Inc.*	Independent Power	1,905,700	7.33%
3				
4				
5				
6	* Earnings are for the first quarter of			
7	2003 only.			
8				
9				
10	During the quarter ended March 31, 2003, Black Hills Power distributed a non-cash dividend to its parent company			
11	Black Hills Corp. The dividend consisted of 10,000 shares of Black Hills Generation, Inc., which represents			
12	100 percent ownership of Black Hills Generation and subsidiaries. As a result, Black Hills Power			
13	no longer has any subsidiaries.			
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50	**TOTAL**		25,994,983	100.00%

CORPORATE ALLOCATIONS

Year: 2003

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Not Significant to Montana Operations					
2						
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34	TOTAL					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2003

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Wyodak Resources	Coal sales to Utility	Fair Market Value (Based on	10,311,246	29.66%	50,292
2	Development Corp.		similar arms-length transactions)			
3						
4	Enserco Energy, Inc.	Gas sales to Utility	Fair Market Value (Based on	6,076,130	0.39%	29,773
5			similar arms-length transactions)			
6						
7	Black Hills FiberCom LLC	Telephone service	Fair Market Value (Based on	115,006	0.29%	609
8			similar arms-length transactions)			
9						
10	Black Hills FiberCom LLC	Miscellaneous	Fair Market Value (Based on	138,529	0.39%	
11			similar arms-length transactions)			
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32	**TOTAL**			16,640,911		80,674

Company Name: **Black Hills Power, Inc.** **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2003

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	Wyodak Resources					
2	Development corp.	Electricity	Wyoming Industrial Rate	705,827	100.00%	
3						
4	FiberCom LLC	Electricity	South Dakota Commercial Rate	337,547	100.00%	
5						
6	Black Hills Wyoming	Transmission Service	Point-to-Point			
7			Open Access Transmission Tariff	1,414,502	100.00%	
8						
9	Black Hills Wyoming	Non-firm energy sales	Fair Market Value (Based on			
10			similar arms-length transactions)	890,962	100.00%	
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32	**TOTAL**			3,348,838		

MONTANA UTILITY INCOME STATEMENT*

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	162,185,957	171,018,600	5.45%
2					
3		Operating Expenses			
4	401	Operation Expenses	71,561,762	84,733,264	18.41%
5	402	Maintenance Expense	7,556,566	8,024,770	6.20%
6	403	Depreciation Expense	17,347,576	18,847,762	8.65%
7	404-405	Amortization of Electric Plant			
8	406	Amort. of Plant Acquisition Adjustments	151,404	151,404	
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	7,409,050	7,929,700	7.03%
12	409.1	Income Taxes - Federal	10,826,589	3,553,955	-67.17%
13		- Other			
14	410.1	Provision for Deferred Income Taxes	4,656,740	9,139,885	96.27%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.		(749,556)	#DIV/0!
16	411.4	Investment Tax Credit Adjustments	(415,957)	(318,304)	23.48%
17	411.6	(Less) Gains from Disposition of Utility Plant			
18	411.7	Losses from Disposition of Utility Plant			
19					
20		**TOTAL Utility Operating Expenses**	119,093,730	131,312,880	10.26%
21		**NET UTILITY OPERATING INCOME**	43,092,227	39,705,720	-7.86%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	5,243.00	5,020.00	-4.25%
3	442	Commercial & Industrial - Small	18,104.00	16,681.00	-7.86%
4		Commercial & Industrial - Large	572,611.00	637,833.00	11.39%
5	444	Public Street & Highway Lighting			
6	445	Other Sales to Public Authorities			
7	446	Sales to Railroads & Railways			
8	448	Interdepartmental Sales			
9					
10		**TOTAL Sales to Ultimate Consumers**	595,958.00	659,534.00	10.67%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	595,958.00	659,534.00	10.67%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	595,958.00	659,534.00	10.67%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	22.00	445.00	1922.73%
19	451	Miscellaneous Service Revenues			
20	453	Sales of Water & Water Power			
21	454	Rent From Electric Property			
22	455	Interdepartmental Rents			
23	456	Other Electric Revenues			
24					
25		**TOTAL Other Operating Revenues**	22.00	445.00	1922.73%
26		**Total Electric Operating Revenues**	595,980.00	659,979.00	10.74%

* Total Company Income Statement

Company Name: **Black Hills Power, Inc.** **SCHEDULE 8A**

Notes to Financial Statements Year: 2003

See Attached

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (the Company) is an electric utility serving customers in South Dakota, Wyoming and Montana. The Company is a wholly owned subsidiary of the publicly traded Black Hills Corporation (the Parent).

Basis of Accounting

The financial statements have been prepared in accordance with the accounting requirements of the Uniform System of Accounts prescribed by the FERC. The principle differences from generally accepted accounting principles include the exclusion of current maturities of long term debt from current liabilities, the requirement to report deferred tax assets and liabilities separately, rather than as a single amount, the recording of asset removal costs as accumulated depreciation rather than as a liability and the exclusion of comparative statements of retained earnings and cash flows. These requirements also require the Company to report its investment in the Subsidiary on the equity basis of accounting versus following the consolidation method of accounting which is required by accounting principles generally accepted in the United States.

Regulatory Accounting

The Company follows the provisions of the Financial Accounting Standards Board (FASB) of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating its electric operations. As a result of the Company's 1995 rate case settlement, a 50-year depreciable life for Neil Simpson II is used for financial reporting purposes. If the Company were not following SFAS 71, a 35 to 40 year life would be more appropriate, which would increase depreciation expense by approximately $0.6 - $1.1 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 the Company's regulated generation operations. In the event the Company determines that it no longer meets the criteria for following SFAS 71, the accounting impact to the Company would be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict the Company's ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure the continuing application of SFAS 71 is appropriate.

Utility Plant

Utility plant is recorded at cost, which includes an allowance for funds used during construction (AFUDC) where applicable. The cost of utility plant retired, together with removal cost less salvage, is charged to accumulated depreciation. Repairs and maintenance of utility plant are charged to operations as incurred.

AFUDC represents the approximate composite cost of borrowed funds and a return on capital used to finance the construction expenditures and is capitalized as a component of electric property. AFUDC was calculated at an annual composite rate of 9.8 percent and 9.1 percent during 2003 and 2002 respectively.

Depreciation

Depreciation is computed on a straight-line method over the estimated useful lives of the related assets. Depreciation provisions were equivalent to annual composite rates of 3.1 percent in 2003 and 2002.

Impairment of Long-Lived 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 2003 or 2002.

Cash Equivalents

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

Inventory

Materials, supplies and fuel are generally stated at cost on a first-in, first-out basis.

Deferred Financing Costs

Deferred financing costs are amortized using the effective interest method over the term of the related debt.

Revenue Recognition

Revenues are recognized based upon delivery of electric energy based on rates filed with the applicable regulatory authorities and include an accrual for estimated unbilled revenue for services provided through year-end. For its investment in unconsolidated subsidiaries, the Company used the equity method to recognize as earnings its pro-rata share of net income or loss of the associated company.

Income Taxes

The Company uses the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

Fuel and Purchased Power Adjustment Tariffs

The Company's Montana Retail Tariffs contain clauses that allow recovery of certain fuel and purchased power costs in excess of the level of such costs included in base rates. These cost adjustment tariffs are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. The adjustments are recognized as current assets or current liabilities until adjusted through future billings to customers. Sales to Montana account for less than 10 percent of the Company's total electric revenue.

The Company's South Dakota, Wyoming, Wholesale to Montana-Dakota Utilities Co., (a division of MDU Resources Group, Inc. (MDU)) and City of Gillette tariffs do not include an automatic fuel and purchased power adjustment tariff.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America and to conform with accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases 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 doubtful accounts, asset valuations and economic useful lives, and employee benefit plans. Actual results could differ from those estimates.

Recently Adopted Accounting Pronouncements

SFAS 132-R

In December 2003, the FASB issued SFAS No. 132 (Revised), "Employer's Disclosure about Pensions and Other Postretirement Benefits" (SFAS 132-R). SFAS 132-R retains disclosure requirements of the original SFAS 132 and requires additional disclosures related to assets, obligations, cash flows, and net periodic benefit cost. SFAS 132-R is effective for fiscal years ending after December 15, 2003, except that certain disclosures are effective for fiscal years ending after June 15, 2004. Interim period disclosures are effective for interim periods beginning after December 15, 2003. The adoption of the disclosure provisions of SFAS 132-R did not have an effect on the Company's Financial Statements (see Note 7).

SFAS 143

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and was effective January 1, 2003. SFAS 143 requires that the present value of retirement costs for which the Company has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. Adoption did not have a material effect on the Company's financial position, results of operations or cash flows.

SFAS 150

In May 2003, the FASB issued SFAS No. 150 "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). SFAS 150 provides accounting and disclosure requirements for classification and measurement of certain financial instruments with characteristics of both liabilities and equity. Management adopted SFAS 150 effective July 1, 2003. Adoption did not have a material effect on the Company's financial position, results of operations or cash flows.

Issue C20

On June 25, 2003, the FASB Derivatives Implementation Group cleared Issue C20, "Scope Exceptions: Interpretation of the Meaning of *Not Clearly and Closely Related* in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (Issue C20). Issue C20 clarifies which contracts qualify for the "normal purchase or sale" exception as provided by paragraph 10(b) of SFAS 133. The Company adopted this guidance on October 1, 2003. Under Issue C20, the Company's long-term power sales contracts either are not considered derivatives, or qualify for the "normal purchase or sale" exception as defined by SFAS 133, therefore adoption of this guidance had no impact on the Company's results of operations and financial position.

Recently Issued Accounting Pronouncements

FSP 106-1

In January 2004, the FASB issued FASB Staff Position (FSP) No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-1), which permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 until remaining questions – notably the issue of how to account for the federal subsidy – are resolved. The Company provides prescription drug benefits to certain eligible employees and has elected the one-time deferral of accounting for the effects of the 2003 Medicare Act. The Company intends to analyze the 2003 Medicare Act, along with the authoritative guidance, when issued, to determine if its benefit plans need to be amended and how to record the effects of the 2003 Medicare Act. Specific guidance on the accounting for the federal subsidy provided by the 2003 Medicare Act is pending and that guidance, when issued, could require the Company to change previously reported postretirement benefit information. For more information on the Company's postretirement benefits, see Note 7.

Supplemental Disclosure of Cash Flow Information

Cash paid during the year 2003 for interest was $17,120,000 and cash paid during the year 2003 for income taxes was $6,745,000.

The Company distributed a stock dividend to Black Hills Corporation, its Parent Company, in the amount of $46.5 million (See Note 10).

(2) CAPITAL STOCK

The Company is a wholly-owned subsidiary of Black Hills Corporation.

(3) LONG-TERM DEBT

Substantially all of the Company's 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. Scheduled maturities are approximately $2.0 million a year for the years 2004 through 2008.

During 2002, the Company entered into a $50 million treasury lock to hedge a portion of the Company's $75 million First Mortgage Bond offering completed in August 2002. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a $1.8 million loss. This treasury lock was treated as a cash flow hedge, in accordance with SFAS 133, and accordingly the resulting loss is carried in Accumulated other comprehensive loss on the Consolidated Balance Sheet and amortized over the life of the related bonds as additional interest expense.

(4) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Long-Term Debt

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

The estimated fair values of the Company's financial instruments at December 31, are as follows (in thousands):

	2003	2002

	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including current maturities)	$ 212,042	$ 238,331	$ 215,137	$ 238,811

(5) JOINTLY OWNED FACILITIES

The Company owns a 20 percent interest and PacifiCorp owns an 80 percent interest in the Wyodak Plant (Plant), a 362 megawatt coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp 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, 2003, the Company's investment in the Plant included $77.2 million in electric plant and $45.5 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 $5.8 million and $5.5 million for the years ended December 31, 2003 and 2002, respectively, and is included in the corresponding categories of operating expenses in the accompanying Statements of Income.

The Company also owns a 35 percent interest and Basin Electric Power Cooperative owns a 65 percent interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie placed into service in the fourth quarter of 2003. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the Western Electricity Coordinating Council (WECC) region and the Mid-Continent Area Power Pool, or "MAPP" region. The total transfer capacity of the tie is 400 megawatts – 200 megawatts West to East and 200 megawatts from East to West. The Company is committed to pay 35 percent of the additions, replacements and operating and maintenance expenses. As of December 31, 2003, the Company's investment in the transmission tie was $20.3 million.

(6) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreement - PacifiCorp

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 megawatts of electric capacity and energy from PacifiCorp'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 PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $10.8 million in 2003, $10.9 million in 2002 (net of a $1.3 million refund for prior years) and $13.9 million in 2001.

In addition, the Company has a firm network transmission agreement for 36 MWs of capacity with PacifiCorp that expires on December 31, 2006. Annual costs are approximately $0.9 million per year. The Company uses this agreement to serve the Sheridan, Wyoming electric service territory under our contract with Montana-Dakota Utilities Company.

The Company also has a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of capacity and energy be transmitted: 32 megawatts in 2001, 27 megawatts in 2002, 22 megawatts in 2003, 17 megawatts in 2004-2006 and 50 megawatts in 2007-2023. Costs incurred under this agreement were $0.5 million in 2003 and $0.7 million in each of 2002 and 2001.

Long-Term Power Sales Agreements

- The Company has a ten-year power sales contract with the Municipal Energy Agency of Nebraska (MEAN) for 20 megawatts of contingent capacity from the Neil Simpson Unit #2 plant.

- The Company has a contract with Montana-Dakota Utilities Company, expiring in 2007, for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy. Both contracts are served by the Company's electric utility and are integrated into our control area and are treated as firm native load.

Legal Proceedings

Forest Fire Claims

In September 2001, a fire occurred in the southwestern Black Hills, now known as the "Hell Canyon Fire." It is alleged that the fire occurred when a high voltage electrical span maintained by the Company broke, and electrical arcing from the severed line ignited dry grass. The fire burned approximately 10,000 acres of land owned by the Black Hills National Forest, the Oglala Sioux Tribe, and other private landowners. The State of South Dakota initiated litigation against the Company, in the Seventh Judicial Circuit Court, Fall River County, South Dakota, on or about January 31, 2003. The Complaint seeks recovery of damages for alleged fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. A substantially similar suit was filed against the Company by the United States Forest Service, on June 30, 2003, in the United States District Court for the District of South Dakota, Western Division. The State subsequently joined its claim in the federal action. The State claims damages in the amount of approximately $0.8 million for fire suppression and rehabilitation costs. The United States Government's claim for fire suppression and related costs has been submitted at approximately $1.3 million. The Company continues to investigate the cause and origin of the fire, and the damage claims. A trial date has been set for early 2005. The Company has denied all claims and will vigorously defend this matter, the timing or outcome of which is uncertain.

On June 29, 2002, a forest fire began near Deadwood, South Dakota, now known as the "Grizzly Gulch Fire." Before being contained more than eight days later, the fire consumed over 10,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 7 homes, and 15 outbuildings. There were no reported personal injuries. In addition, the fire burned to the edge of the City of Deadwood, forcing the evacuation of the City of Deadwood, and the adjacent City of Lead, South Dakota. These communities are active in the tourist and gaming industries. Individuals were ordered to leave their homes, and businesses were closed for a short period of time. On July 16, 2002, the State of South Dakota announced the results of its investigation of the cause and origin of the fire. The State asserted that the fire was caused by tree encroachment into and contact with a transmission line owned and maintained by the Company.

On September 6, 2002, the State of South Dakota commenced litigation against the Company, in the Seventh Judicial Circuit Court, Pennington County, South Dakota. The Complaint seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A claim for treble damages was asserted with respect to the claim for injury to timber.

On March 3, 2003, the United States of America filed a similar suit against the Company, in the United States District Court, District of South Dakota, Western Division. The federal government's Complaint likewise seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A similar claim for treble damages is asserted with respect to the claim for injury to timber. In April 2003, the State of South Dakota intervened in the federal action. Accordingly, the state court litigation will be stayed, and all governmental claims will be tried in U.S. District Court.

The state and federal government claim approximately $5.3 million for suppression costs, $1.2 million for rehabilitation costs, and $0.6 million for timber loss. Additional claims could be asserted for alleged loss of habitat and aesthetics or for assistance to private landowners.

The Company is completing its own investigation of the fire cause and origin. The Company's investigation is continuing, but based upon information currently available, the Company filed its Answer to the Complaints of both the State and the United States government, denying all claims, and asserting that the fire was caused by an independent intervening cause, or an act of God. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April through November 2003, various private civil actions were filed against the Company, asserting that the Grizzly Gulch Fire caused damage to the parties' real property. These actions were filed in the Fourth Judicial Circuit Court, Lawrence County, South Dakota. The Complaints seek recovery on the same theories asserted in the governmental Complaints, but most of the Complaints specify no amount for damage claims. The Company will vigorously defend these matters as well.

Additional claims could be made for individual and business losses relating to injury to personal and real property, and lost income.

Although we cannot predict the outcome or the viability of potential claims with respect to either fire, based on the information available, management believes that any such claims, if determined adversely to the Company, will not have a material adverse effect on the Company's financial condition or results of operations.

PPM Energy, Inc. Demand for Arbitration

On January 2, 2004, PPM Energy, Inc. delivered its Demand for Arbitration to the Company. The Demand alleges claims for breach of contract and requests a declaration of the parties' rights and responsibilities under an Exchange Agreement executed on or about April 3, 2001. Specifically, PPM Energy asserts that the Exchange Agreement obligates the Company to accept receipt and cause corresponding delivery of electric energy, and to grant access to transmission rights allegedly covered by the Agreement. PPM Energy requests an award of damages in an amount not less than $20.0 million. The Company denies all claims and will vigorously defend this matter, the timing and outcome of which is uncertain.

Ongoing Litigation

The Company is subject to various other legal proceedings, claims and litigation 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 financial position or results of operations of the Company.

(7) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company. 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. The Company uses a September 30 measurement date for the Plan.

Obligations and Funded Status

Change in benefit obligation:

	2003	2002
	(in thousands)	
Projected benefit obligation at beginning of year	$ 38,141	$ 33,151
Service cost	714	588
Interest cost	2,500	2,406
Actuarial loss	1,110	571
Discount rate change	4,239	3,380
Benefits paid	(1,972)	(1,955)
Amendments	—	—
Taxable wage rate and cost of living rate change	71	—
Net increase	6,662	4,990
Projected benefit obligation at end of year	$ 44,803	$ 38,141

A reconciliation of the fair value of Plan assets (as of the September 30 measurement date) is as follows:

	2003	2002
	(in thousands)	
Beginning market value of plan assets	$ 25,830	$ 32,938
Benefits paid	(1,972)	(1,955)
Investment income (loss)	6,406	(5,153)
Employer contributions	6,851	—
Ending market value of plan assets	$ 37,115	$ 25,830

Funding information for the Plan is as follows:

	2003	2002
	(in thousands)	
Fair value of plan assets	$ 37,115	$ 25,830
Projected benefit obligation	(44,803)	(38,141)
Funded status	(7,688)	(12,311)
Unrecognized:		
Net loss	17,457	17,075
Prior service cost	1,088	1,253
Net amount recognized	$ 10,857	$ 6,017

Amounts recognized in statement of financial position consist of:

	2003	2002
	(in thousands)	
Net pension (liability) asset	$ 10,857	$ (6,370)
Intangible asset	—	1,326
Accumulated other comprehensive loss	—	11,061
Net amount recognized	$ 10,857	$ 6,017
Accumulated benefit obligation	$ 36,577	$ 32,254

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of $10.9 million at December 31, 2003 and is included in the line item Other in Other assets on the accompanying Balance Sheets.

The provisions of SFAS No. 87 required the Company to record an accrued pension liability of $6.4 million at December 31, 2002 and is included in the line item Other in Deferred credits and other liabilities on the accompanying Balance Sheets.

Components of Net Periodic Pension Expense

	2003	2002
	(in thousands)	
Service cost	$ 714	$ 588
Interest cost	2,500	2,406
Expected return on assets	(2,473)	(3,345)
Amortization of prior service cost	165	184
Recognized net actuarial (gain) loss	1,105	96
Net pension (income) expense	$ 2,011	$ (71)

Additional Information

	2003	2002
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$11,061	$(11,061)

Assumptions

Weighted-average assumptions used to determine benefit obligations:	2003	2002
Discount rate	6.00%	6.75%
Rate of increase in compensation levels	5.00%	5.00%

Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2003	2002
Discount rate*	6.75%	7.50%
Expected long-term rate of return on assets**	10.00%	10.50%
Rate of increase in compensation levels	5.00%	5.00%

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* The discount rate used for net periodic pension cost was changed from 6.75 percent in 2003 to 6.0 percent for the calculation of the 2004 net periodic pension cost. This change is expected to affect pension costs in 2004 by an increase of approximately $0.4 million.

**The expected rate of return on plan assets was changed from 10.0 percent in 2003 to 9.5 percent for the calculation of the 2004 net periodic pension cost. This change is expected to increase pension costs in 2004 by approximately $0.2 million.

The Plan's expected long-term rate of return on assets assumption is based upon the weighted average expected long-term rate of returns for each individual asset class. The asset class weighting is determined using the target allocation for each asset class in the Plan portfolio. The expected long-term rate of return for each asset class is determined primarily from long-term historical returns for the asset class, with adjustments if it is anticipated that long-term future returns will not achieve historical results.

The expected long-term rate of return for equity investments was 10.5 percent and 11.0 percent for the 2003 and 2002 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2002, 12.5 percent, 10.5 percent, 10.3 percent and 10.9 percent respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on intermediate-term treasury bonds of 6.3 percent from 1950 to 2002. The expected long-term rate of return on cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below long-term returns on intermediate-term treasury bonds.

Plan Assets

Percentage of fair value of Plan assets at September 30:

	2003	2002
Domestic equity	44.8%	63.0%
Foreign equity	26.6%	25.9%
Fixed income	3.8%	7.8%
Cash	24.8%[(a)]	3.3%
Total	100.0%	100.0%

(a) Allocation includes $6.9 million cash contribution made to the plan on September 30, 2003; the contribution is expected to be placed in noncash investments in the fiscal 2004 plan year.

The Plan's investment policy includes a target asset allocation as follows:

Asset Class	Target Allocation
US Stock	60% (with a variance of no more or less than 10% of target).
Foreign Stocks	30% (with a variance of no more or less than 10% of target).
Fixed Income	5% (with a variance of no more than 10% or no less than 5% of target).
Cash	5% (with a variance of no more than 10% or no less than 5% of target).

The Plan's investment policy includes the investment objective that the achieved long-term rate of return meet or exceed the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity-based assets. The policy provides that the Plan will maintain a passive core US Stock portfolio based on the S&P 500 Index. Complementing this core will be investments in US and foreign equities through actively managed mutual funds.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Plan may invest, including prohibitions on short sales and the use of options or futures contracts. With regards to pooled funds, the policy requires the evaluation of the appropriateness of such funds for managing Plan assets if a fund engages in such transactions. The Plan has historically not invested in funds engaging in such transactions.

Contributions

The Company made a contribution to the Plan of $6.9 million on September 30, 2003. The Company does not anticipate that a contribution will be made to the Plan in the 2004 fiscal year.

Supplemental Nonqualified Defined Benefit Retirement Plans

The Company has various supplemental retirement plans for outside directors and key executives of the Company. The plans are nonqualified defined benefit plans. The Company uses a September 30 measurement date for the Plans.

Obligations and Funded Status

	2003	2002
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$ 1,676	$ 1,282
Service cost	6	22
Interest cost	109	116
Actuarial losses	197	358
Benefits paid	(102)	(102)
Net increase	210	394
Projected benefit obligation at end of year	$ 1,886	$ 1,676
Fair value of plan assets at end of year		
Funded status	$ (1,886)	$ (1,676)
Unrecognized net loss	824	670
Unrecognized prior service cost	4	1
Contributions	25	25
Net amount recognized	$ (1,033)	$ (980)

	2003	2002
	(in thousands)	
Amounts recognized in statement of financial position consist of:		
Net pension (liability)	$ (1,613)	$ (1,388)
Intangible asset	4	1
Contributions	25	25
Accumulated other comprehensive loss	551	382
Net amount recognized	$ (1,033)	$ (980)
Accumulated benefit obligation	$ 1,615	$ 1,445

The provisions of SFAS 87 required the Company to record an accrued pension liability of $1.6 million and $1.4 million at December 31, 2003 and 2002, and is included in Deferred credits and other liabilities, Other on the accompanying Balance Sheets.

Components of Net Periodic Benefit Cost

	2003	2002
	(in thousands)	
Service cost	$ 6	$ 22
Interest cost	109	116
Prior service cost	(3)	(2)
(Gain) loss	42	42
Net periodic benefit cost	$ 154	$ 178

Additional Information

	2003	2002
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ (169)	$ (382)

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2003	2002
Discount rate	6.00%	6.75%
Rate of increase in compensation levels	5.00%	5.00%

Weighted-average assumptions used to determine net periodic benefit cost for plan year	2003	2002
Discount rate*	6.75%	7.50%
Rate of increase in compensation levels	5.00%	5.00%

*The discount rate used for net periodic benefit cost was changed from 6.75 percent in 2003 to 6.0 percent for the calculation of the 2004 net periodic benefit cost. This change will not materially affect benefit costs in 2004.

Plan Assets

The plan has no assets. The Company funds on a cash basis as benefits are paid.

Contributions

The Company anticipates that contributions to the plan for the next fiscal year will be approximately $0.1 million; the contributions are expected to be in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in the Company's Postretirement Healthcare 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. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. The Company may amend or change the Plan periodically. The Company is not pre-funding its retiree medical plan. The Company uses a September 30 measurement date for the Plan.

These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plan.

Obligation and Funded Status

	2003	2002
	(in thousands)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of year	$ 6,547	$ 7,275
Service cost	198	160
Interest cost	435	402
Plan participant's contributions	319	337
Amendments	—	(284)
Benefits paid and actual expenses	(480)	(483)
Net transfer in/out	—	(433)
Actuarial (gains) losses	1,178	(427)
Net increase	1,650	(728)
Accumulated postretirement benefit obligation at end of year	$ 8,197	$ 6,547
Fair value of plan assets at end of year		
Funded status	$ (8,197)	$ (6,547)
Unrecognized net loss	2,930	1,830
Unrecognized prior service cost	(246)	(265)
Unrecognized transition obligation	1,050	1,167
Contributions	42	51
Net amount recognized	$ (4,421)	$ (3,764)

Amounts recognized in statement of financial position consist of:

	2003	2002
	(in thousands)	
Accrued postretirement (liability)	$ (4,421)	$ (3,764)

Components of Net Periodic Benefit Cost

	2003	2002
	(in thousands)	
Service cost	$ 198	$ 160
Interest cost	435	402
Amortization of transition obligation	117	117
Amortization of prior service cost	(19)	(19)
Loss	78	34
Net periodic benefit cost	$ 809	$ 694

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30

	2003	2002
Discount rate	6.00%	6.75%

Weighted-average assumptions used to determine net periodic benefit cost for plan year

	2003	2002
Discount rate*	6.75%	7.50%

*The discount rate used for net periodic benefit cost was changed from 6.75 percent in 2003 to 6.0 percent for the calculation of the 2004 net periodic benefit cost. This change is expected to affect benefit costs in 2004 by an increase of approximately $0.1 million.

The healthcare trend rate assumption for the 2003 fiscal year expense was 11 percent for fiscal 2003 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2009. The health care trend rate assumption for 2003 fiscal year disclosure and 2004 fiscal year expense is 12 percent for fiscal 2004 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011.

A 1 percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.1 million or 21 percent and the accumulated periodic postretirement benefit obligation $1.1 million or 14 percent. A 1 percent decrease would reduce the service and interest cost by $0.1 million or 16 percent and the accumulated periodic postretirement benefit obligation $0.9 million or 11 percent.

Plan Assets

The plan has no assets. The Company funds on a cash basis as benefits are paid.

Contributions

The Company anticipates that contributions to the plan for the next fiscal year will be approximately $0.5 million in the form of benefits and administrative costs paid.

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. 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 $0.4 million for 2003, $0.4 million for 2002 and $0.6 million for 2001.

(8) OTHER COMPREHENSIVE INCOME (LOSS)

The following tables display the related tax effects allocated to each component of Other Comprehensive Income (Loss) for the years ended December 31, (in thousands):

	2003		
	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Minimum pension liability adjustment	$ 10,892	$(3,813)	$ 7,079
Net change in fair value of derivatives designated as cash flow hedges associated with discontinued operations	672	(269)	403
Amortization of cash flow hedges settled and deferred in accumulated other comprehensive loss and reclassified into interest expense	64	(22)	42
Other comprehensive income	$ 11,628	$(4,104)	$ 7,524

	2002		
	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Net change in fair value of derivatives designated as cash flow hedges, including some of which have been classified into discontinued operations	$ (9,762)	$ 3,669	$ (6,093)
Minimum pension liability adjustment	(11,443)	4,005	(7,438)
Other comprehensive loss	$(21,205)	$ 7,674	$(13,531)

(9) INCOME TAXES

Income tax expense for the years ended December 31 was (in thousands):

	2003	2002
Current	$ 3,550	$10,826
Deferred	8,072	4,241
	$11,622	$15,067

The temporary differences which gave rise to the net deferred tax liability were as follows (in thousands):

Years ended December 31,	2003	2002
Deferred tax assets, current:		
Valuation reserve	$ 314	$ 309
Employee benefits	2,623	2,375
Items of other comprehensive income	—	4,028
Other	624	791
	3,561	7,503
Deferred tax liabilities, current:		
Employee benefits	3,800	2,106
	3,800	2,106
Net deferred tax (liability) asset, current	$ (239)	$ 5,397
Deferred tax assets, non-current:		
Regulatory asset	$ 1,156	$ 1,295
ITC	460	571
Items of other comprehensive income	806	612
Other	789	632
	3,211	3,110
Deferred tax liabilities, non-current:		
Accelerated depreciation and other plant related differences	63,615	56,284
AFUDC	2,808	2,828
Regulatory liability	1,512	1,523
Other	909	1,014
	68,844	61,649
Net deferred tax liability, non-current	$ 65,633	$ 58,539
Net deferred tax liability	$ 65,872	$ 53,142

The following table reconciles the change in the net deferred income tax liability from December 31, 2002, to December 31, 2003, to deferred income tax expense:

	2003 (in thousands)
Increase in deferred income tax liability from the preceding table	$ 12,730
Deferred taxes associated with ITC	(716)
Deferred taxes associated with other comprehensive loss	(3,834)
Other	(108)
Deferred income tax expense for the period	$ 8,072

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

	2003	2002
Federal statutory rate	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(1.3)	(1.3)
Research and development credit	(0.1)	—
Other	(1.1)	(0.4)
	32.5%	33.3%

(10) NON-CASH DIVIDEND

During the quarter ended March 31, 2003, the Company distributed a non-cash dividend to its parent company, Black Hills Corporation (Parent). The dividend consisted of 10,000 common shares of Black Hills Generation, Inc., formerly known as Black Hills Energy Capital, Inc., (Generation), which represents 100 percent ownership of Generation. The Company therefore no longer operates in the independent power production business. As a result, the Company no longer has any subsidiaries and operates only in the electric utility business. The Company's investment in Generation at the time of the distribution was $46.5 million.

MONTANA OPERATION & MAINTENANCE EXPENSES*

Year: 2003

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,615,679	1,074,077	-33.52%
6	501 Fuel	13,512,582	13,601,760	0.66%
7	502 Steam Expenses	2,352,182	2,680,711	13.97%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	869,052	794,104	-8.62%
11	506 Miscellaneous Steam Power Expenses	785,951	1,127,836	43.50%
12	507 Rents			
13				
14	TOTAL Operation - Steam	19,135,446	19,278,488	0.75%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	266,494	198,873	-25.37%
18	511 Maintenance of Structures	172,047	396,449	130.43%
19	512 Maintenance of Boiler Plant	2,106,803	2,957,495	40.38%
20	513 Maintenance of Electric Plant	590,018	876,036	48.48%
21	514 Maintenance of Miscellaneous Steam Plant	476,679	546,764	14.70%
22				
23	TOTAL Maintenance - Steam	3,612,041	4,975,617	37.75%
24				
25	**TOTAL Steam Power Production Expenses**	22,747,487	24,254,105	6.62%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear		-	
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear		-	
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2003

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering			
5	536 Water for Power			
6	537 Hydraulic Expenses			
7	538 Electric Expenses			
8	539 Miscellaneous Hydraulic Power Gen. Expenses			
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic		-	
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering			
15	542 Maintenance of Structures			
16	543 Maint. of Reservoirs, Dams & Waterways			
17	544 Maintenance of Electric Plant			
18	545 Maintenance of Miscellaneous Hydro Plant			
19				
20	TOTAL Maintenance - Hydraulic		-	
21				
22	**TOTAL Hydraulic Power Production Expenses**		-	
23				
24	Other Power Generation			
25	Operation			
26	546 Operation Supervision & Engineering	50,699	78,706	55.24%
27	547 Fuel	5,979,373	7,361,231	23.11%
28	548 Generation Expenses	408,311	334,850	-17.99%
29	549 Miscellaneous Other Power Gen. Expenses	47,348	45,525	-3.85%
30	550 Rents	(450,000)		100.00%
31				
32	TOTAL Operation - Other	6,035,731	7,820,312	29.57%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	43,560	49,496	13.63%
36	552 Maintenance of Structures	6,514	20,412	213.36%
37	553 Maintenance of Generating & Electric Plant	1,956,898	868,315	-55.63%
38	554 Maintenance of Misc. Other Power Gen. Plant	8,401	10,260	22.13%
39				
40	TOTAL Maintenance - Other	2,015,373	948,483	-52.94%
41				
42	**TOTAL Other Power Production Expenses**	8,051,104	8,768,795	8.91%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	25,900,572	34,520,289	33.28%
46	556 System Control & Load Dispatching			
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	25,900,572	34,520,289	33.28%
50				
51	**TOTAL Power Production Expenses**	56,699,163	67,543,189	19.13%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	206,437	191,164	-7.40%
4	561	Load Dispatching	701,111	707,498	0.91%
5	562	Station Expenses	85,700	109,121	27.33%
6	563	Overhead Line Expenses	50,102	25,236	-49.63%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	1,690,839	1,971,245	16.58%
9	566	Miscellaneous Transmission Expenses	166,927	196,171	17.52%
10	567	Rents			
11					
12		TOTAL Operation - Transmission	2,901,116	3,200,435	10.32%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	53,676	37,345	-30.43%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	82,378	71,081	-13.71%
17	571	Maintenance of Overhead Lines	300,071	207,311	-30.91%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21		TOTAL Maintenance - Transmission	436,125	315,737	-27.60%
22					
23		**TOTAL Transmission Expenses**	3,337,241	3,516,172	5.36%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	566,865	545,718	-3.73%
28	581	Load Dispatching	141,292	96,212	-31.91%
29	582	Station Expenses	284,398	283,982	-0.15%
30	583	Overhead Line Expenses	556,977	379,587	-31.85%
31	584	Underground Line Expenses	210,414	203,236	-3.41%
32	585	Street Lighting & Signal System Expenses	533	956	79.36%
33	586	Meter Expenses	155,078	500,598	222.80%
34	587	Customer Installations Expenses	42,197	45,674	8.24%
35	588	Miscellaneous Distribution Expenses	296,862	414,274	39.55%
36	589	Rents	22,935	22,461	-2.07%
37					
38		TOTAL Operation - Distribution	2,277,551	2,492,698	9.45%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	26,154	21,387	-18.23%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	52,029	32,251	-38.01%
43	593	Maintenance of Overhead Lines	929,742	1,199,937	29.06%
44	594	Maintenance of Underground Lines	111,071	143,583	29.27%
45	595	Maintenance of Line Transformers	10,481	14,458	37.94%
46	596	Maintenance of Street Lighting, Signal Systems	82,687	101,449	22.69%
47	597	Maintenance of Meters	36,255	49,400	36.26%
48	598	Maintenance of Miscellaneous Dist. Plant	31,925	23,019	-27.90%
49					
50		TOTAL Maintenance - Distribution	1,280,344	1,585,484	23.83%
51					
52		**TOTAL Distribution Expenses**	3,557,895	4,078,182	14.62%

Company Name: Black Hills Power, Inc.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2003

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	120,661	94,722	-21.50%
4	902 Meter Reading Expenses	980,843	826,649	-15.72%
5	903 Customer Records & Collection Expenses	1,957,965	1,682,667	-14.06%
6	904 Uncollectible Accounts Expenses	476,827	427,090	-10.43%
7	905 Miscellaneous Customer Accounts Expenses	1,071,086	934,079	-12.79%
8				
9	TOTAL Customer Accounts Expenses	4,607,382	3,965,207	-13.94%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	62,305	64,054	2.81%
14	908 Customer Assistance Expenses	769,339	804,563	4.58%
15	909 Informational & Instructional Adv. Expenses	6,157	6,802	10.48%
16	910 Miscellaneous Customer Service & Info. Exp.	37,364	43,237	15.72%
17				
18	TOTAL Customer Service & Info Expenses	875,165	918,656	4.97%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses			
24	913 Advertising Expenses			
25	916 Miscellaneous Sales Expenses			
26				
27	TOTAL Sales Expenses		-	
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	3,814,996	4,376,608	14.72%
32	921 Office Supplies & Expenses	238,882	315,616	32.12%
33	922 (Less) Administrative Expenses Transferred - Cr.	(30,037)	(16,005)	46.72%
34	923 Outside Services Employed	3,141,413	2,982,675	-5.05%
35	924 Property Insurance	499,524	1,002,680	100.73%
36	925 Injuries & Damages	506,389	639,134	26.21%
37	926 Employee Pensions & Benefits	1,218,107	2,396,761	96.76%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	161,241	298,299	85.00%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	116,899	177,765	52.07%
42	930.2 Miscellaneous General Expenses	144,681	186,191	28.69%
43	931 Rents	16,704	177,455	962.35%
44				
45	TOTAL Operation - Admin. & General	9,828,799	12,537,179	27.56%
46	Maintenance			
47	935 Maintenance of General Plant	212,683	199,449	-6.22%
48				
49	**TOTAL Administrative & General Expenses**	10,041,482	12,736,628	26.84%
50				
51	**TOTAL Operation & Maintenance Expenses**	79,118,328	92,758,034	17.24%

*Total Company Operation and Maintenance Expense

MONTANA TAXES OTHER THAN INCOME

Year: 2003

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel			
5	Montana PSC	2,252	827	-63.28%
6	Franchise Taxes			
7	Property Taxes	56,258	70,351	25.05%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	1,943	2,027	4.32%
10				
11				
12				
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48				
49				
50				
51	**TOTAL MT Taxes Other Than Income**	60,453	73,205	21.09%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES Year: 2003

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts to Montana Are Not Significant				
2					
3					
4					
5					
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47					
48					
49					
50	**TOTAL Payments for Services**				

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2003

	Description	Total Company	Montana	% Montana
1	NONE			
2				
3				
4				
5				
6				
7				
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48				
49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2003

1	Plan Name			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? _Project Unit Cost Method	IRS Code: 401(b)		
4	Annual Contribution by Employer: $0	Is the Plan Over Funded? No		
5				

	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	38,140,491	33,150,798	-13.08%
8	Service cost	713,597	588,382	-17.55%
9	Interest Cost	2,500,415	2,405,741	-3.79%
10	Plan participants' contributions			
11	Amendments		3,380,240	#DIV/0!
12	Actuarial Gain	5,420,623	570,488	-89.48%
13	Acquisition		-	
14	Benefits paid	(1,971,807)	(1,955,158)	0.84%
15	Benefit obligation at end of year	44,803,319	38,140,491	-14.87%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	25,829,604	32,937,581	27.52%
18	Actual return on plan assets	6,406,472	(5,152,819)	-180.43%
19	Acquisition		-	
20	Employer contribution	6,850,788		-100.00%
21	Plan participants' contributions	-	-	
22	Benefits paid	(1,971,807)	(1,955,158)	0.84%
23	Fair value of plan assets at end of year	37,115,057	25,829,604	-30.41%
24	**Funded Status**	(7,688,262)	(12,310,887)	-60.13%
25	Unrecognized net actuarial loss	17,456,980	17,074,650	-2.19%
26	Unrecognized prior service cost	1,087,888	1,253,350	15.21%
27	Prepaid (accrued) benefit cost	10,856,606	6,017,113	-44.58%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	6.75%	7.50%	11.11%
31	Expected return on plan assets	10.00%	10.50%	5.00%
32	Rate of compensation increase	5.00%	5.00%	
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	713,597	588,382	-17.55%
36	Interest cost	2,500,415	2,405,741	-3.79%
37	Expected return on plan assets	(2,473,229)	(3,345,649)	-35.27%
38	Amortization of prior service cost	165,462	184,120	11.28%
39	Recognized net actuarial loss	1,105,050	95,982	-91.31%
40	Net periodic benefit cost	2,011,295	(71,424)	-103.55%
41				
42	**Montana Intrastate Costs:**			
43	Pension Costs			
44	Pension Costs Capitalized			
45	Accumulated Pension Asset (Liability) at Year End			
46	**Number of Company Employees:**			
47	Covered by the Plan	811	766	-5.55%
48	Not Covered by the Plan	31	30	-3.23%
49	Active	479	447	-6.68%
50	Retired	159	155	-2.52%
51	Deferred Vested Terminated	142	134	-5.63%

Other Post Employment Benefits (OPEBS)

Year: 2003

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: ___________			
4	Order number: ___________			
5	Amount recovered through rates			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	6.75	7.50%	-98.89%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	12.00%	12.00%	
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase	5.00%	5.00%	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	TOTAL COMPANY			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	3,764,185	3,428,514	(0)
20	Service cost	198,323	160,220	(0)
21	Interest Cost	435,106	401,566	(0)
22	Plan participants' contributions			-
23	Amendments			-
24	Actuarial Gain	175,482	(71,944)	(1)
25	Acquisition			-
26	Benefits paid	(152,490)	(154,171)	(0)
27	Benefit obligation at end of year	4,420,606	3,764,185	(0)
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	-		-
30	Actual return on plan assets			-
31	Acquisition			-
32	Employer contribution			-
33	Plan participants' contributions	-	-	-
34	Benefits paid	-	-	-
35	Fair value of plan assets at end of year	-	-	-
36	**Funded Status**	(4,420,606)	(3,764,185)	0
37	Unrecognized net actuarial loss			-
38	Unrecognized prior service cost			-
39	Prepaid (accrued) benefit cost	(4,420,606)	(3,764,185)	0
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	198,323	160,220	(0)
42	Interest cost	435,106	401,566	(0)
43	Expected return on plan assets	-	-	-
44	Amortization of prior service cost			-
45	Recognized net actuarial loss	175,482	132,096	(0)
46	Net periodic benefit cost	808,911	693,882	(0)
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			-
49	Amount Funded through 401(h)			-
50	Amount Funded through Other ______________			-
51	**TOTAL**	-	-	-
52	Amount that was tax deductible - VEBA			-
53	Amount that was tax deductible - 401(h)			-
54	Amount that was tax deductible - Other __________			-
55	TOTAL	-	-	-

Company Name: Black Hills Power, Inc.

SCHEDULE 15

Other Post Employment Benefits (OPEBS) Continued

Year: 2003

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	683	665	(0)
3	Not Covered by the Plan			-
4	Active	472	436	(0)
5	Retired	116	129	0
6	Spouses/Dependants covered by the Plan	95	100	0
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	-	-	-
10	Service cost			-
11	Interest Cost			-
12	Plan participants' contributions			-
13	Amendments			-
14	Actuarial Gain			-
15	Acquisition			-
16	Benefits paid			-
17	Benefit obligation at end of year	-	-	-
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	-	-	-
20	Actual return on plan assets			-
21	Acquisition			-
22	Employer contribution			-
23	Plan participants' contributions	-	-	-
24	Benefits paid	-	-	-
25	Fair value of plan assets at end of year	-	-	-
26	**Funded Status**	-	-	-
27	Unrecognized net actuarial loss			-
28	Unrecognized prior service cost			-
29	Prepaid (accrued) benefit cost	-	-	-
30	**Components of Net Periodic Benefit Costs**			
31	Service cost	-	-	-
32	Interest cost	-	-	-
33	Expected return on plan assets	-	-	-
34	Amortization of prior service cost			-
35	Recognized net actuarial loss			-
36	Net periodic benefit cost	-	-	-
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			-
39	Amount Funded through 401(h)			-
40	Amount Funded through other ____________			-
41	**TOTAL**	-	-	-
42	Amount that was tax deductible - VEBA			-
43	Amount that was tax deductible - 401(h)			-
44	Amount that was tax deductible - Other			-
45	TOTAL	-	-	-
46	**Montana Intrastate Costs:**			
47	Pension Costs			-
48	Pension Costs Capitalized			-
49	Accumulated Pension Asset (Liability) at Year End			-
50	**Number of Montana Employees:**			
51	Covered by the Plan			-
52	Not Covered by the Plan			-
53	Active			-
54	Retired			-
55	Spouses/Dependants covered by the Plan			

Company Name: **Black Hills Power, Inc.**

SCHEDULE 16

Year: 2003

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Daniel P. Landguth Chairman	528,419	176,126	643,653	1,348,198	2,872,325	-53%
2	Everett E. Hoyt Vice-Chariman	356,396	97,036	1,052,234	1,505,666	1,110,203	36%
3	Mark T. Thies Senior Vice President and Chief Financial Officer	254,869	136,776	98,193	489,838	473,563	3%
4	Russell L. Cohen Senior Vice President and Chief Risk Officer	230,192	155,800	21,007	406,999	140,648	189%
5	David R. Emery President & CEO	249,866	76,713	72,998	399,577	431,836	-7%

BALANCE SHEET

Year: 2003

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	549,265,445	594,716,449	-8%
4	101.1 Property Under Capital Leases			
5	102 Electric Plant Purchased or Sold			
6	104 Electric Plant Leased to Others			
7	105 Electric Plant Held for Future Use			
8	106 Completed Constr. Not Classified - Electric	40,571,198	30,922,544	31%
9	107 Construction Work in Progress - Electric	19,212,319	3,059,757	528%
10	108 (Less) Accumulated Depreciation	(210,221,698)	(223,454,961)	6%
11	111 (Less) Accumulated Amortization			
12	114 Electric Plant Acquisition Adjustments	4,870,308	4,870,308	
13	115 (Less) Accum. Amort. Elec. Acq. Adj.	(1,766,383)	(1,917,787)	8%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	401,931,189	408,196,310	-2%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property	5,618	5,618	
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.	(3,956)	(3,956)	
20	123 Investments in Associated Companies			
21	123.1 Investments in Subsidiary Companies	44,142,222	-	#DIV/0!
22	124 Other Investments	2,681,314	3,181,746	-16%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	46,825,198	3,183,408	1371%
25				
26	**Current & Accrued Assets**			
27	131 Cash	514,523	1,048,254	-51%
28	132-134 Special Deposits			
29	135 Working Funds	3,325	3,325	
30	136 Temporary Cash Investments			
31	141 Notes Receivable	270,496		#DIV/0!
32	142 Customer Accounts Receivable	12,726,692	11,633,325	9%
33	143 Other Accounts Receivable	4,276,148	1,292,948	231%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(881,643)	(898,380)	2%
35	145 Notes Receivable - Associated Companies	52,508,097	37,709,836	39%
36	146 Accounts Receivable - Associated Companies	1,745,108	907,793	92%
37	151 Fuel Stock	2,063,934	1,580,687	31%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	7,677,933	7,984,775	-4%
41	155 Merchandise			
42	156 Other Material & Supplies	120	(39)	408%
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed		(5,216)	100%
45	165 Prepayments		13,670,038	-100%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues		4,679,848	-100%
49	174 Miscellaneous Current & Accrued Assets			
50	**TOTAL Current & Accrued Assets**	80,904,733	79,607,194	2%

Company Name: Black Hills Power, Inc.

BALANCE SHEET

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	2,200,013	2,092,634	5%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	183	Prelim. Survey & Investigation Charges		9	-100%
10	184	Clearing Accounts	126,130	304,716	-59%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	4,554,339	2,163,698	110%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	279,649	246,861	13%
16	190	Accumulated Deferred Income Taxes	14,962,961	10,478,780	43%
17		**TOTAL Deferred Debits**	22,123,092	15,286,698	45%
18					
19		**TOTAL Assets & Other Debits**	551,784,212	506,273,610	9%
	Account Title		Last Year	This Year	% Change
20					
21		**Liabilities and Other Credits**			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	23,416,396	23,416,396	
26	202	Common Stock Subscribed			
27	204	Preferred Stock Issued			
28	205	Preferred Stock Subscribed			
29	207	Premium on Capital Stock	83,462,756	42,050,811	98%
30	211	Miscellaneous Paid-In Capital			
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	(2,501,882)	(2,501,882)	
33	215	Appropriated Retained Earnings			
34	216	Unappropriated Retained Earnings	131,906,311	114,097,956	16%
35	217	(Less) Reacquired Capital Stock			
36	219	Accumulated Other Comprehensive Income	(18,055,404)	(1,494,224)	
37		**TOTAL Proprietary Capital**	218,228,177	175,569,057	24%
38					
39	**Long Term Debt**				
40					
41	221	Bonds	187,298,236	184,230,000	2%
42	222	(Less) Reacquired Bonds			
43	223	Advances from Associated Companies			
44	224	Other Long Term Debt	27,838,852	27,811,728	0%
45	225	Unamortized Premium on Long Term Debt			
46	226	(Less) Unamort. Discount on L-Term Debt-Dr.			
47		**TOTAL Long Term Debt**	215,137,088	212,041,728	1%

Company Name: Black Hills Power, Inc.

BALANCE SHEET

Year: 2003

	Account Number & Title		This Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages			
9	228.3	Accumulated Provision for Pensions & Benefits			
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		**TOTAL Other Noncurrent Liabilities**		-	
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	13,651,900	6,441,811	112%
18	233	Notes Payable to Associated Companies	946		#DIV/0!
19	234	Accounts Payable to Associated Companies	2,584,334	7,909,460	-67%
20	235	Customer Deposits	441,320	494,179	-11%
21	236	Taxes Accrued	6,425,453	6,415,969	0%
22	237	Interest Accrued	5,119,793	5,043,269	2%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	559,893	487,615	15%
27	242	Miscellaneous Current & Accrued Liabilities	4,029,873	3,737,832	8%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	32,813,512	30,530,135	7%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,568,359	2,046,869	-23%
34	253	Other Deferred Credits	18,651,132	12,742,428	46%
35	255	Accumulated Deferred Investment Tax Credits	1,631,563	1,313,259	24%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	63,754,381	72,030,134	-11%
39		**TOTAL Deferred Credits**	85,605,435	88,132,690	-3%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		551,784,212	506,273,610	9%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2003

Account Number & Title	Last Year	This Year	% Change
Intangible Plant			
301 Organization			
302 Franchises & Consents			
303 Miscellaneous Intangible Plant			
TOTAL Intangible Plant			
Production Plant			
Steam Production			
310 Land & Land Rights			
311 Structures & Improvements			
312 Boiler Plant Equipment			
313 Engines & Engine Driven Generators			
314 Turbogenerator Units			
315 Accessory Electric Equipment			
316 Miscellaneous Power Plant Equipment			
TOTAL Steam Production Plant			
Nuclear Production			
320 Land & Land Rights			
321 Structures & Improvements			
322 Reactor Plant Equipment			
323 Turbogenerator Units			
324 Accessory Electric Equipment			
325 Miscellaneous Power Plant Equipment			
TOTAL Nuclear Production Plant			
Hydraulic Production			
330 Land & Land Rights			
331 Structures & Improvements			
332 Reservoirs, Dams & Waterways			
333 Water Wheels, Turbines & Generators			
334 Accessory Electric Equipment			
335 Miscellaneous Power Plant Equipment			
336 Roads, Railroads & Bridges			
TOTAL Hydraulic Production Plant			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2003

	Account Number & Title		Last Year	This Year	% Change
1					
2		Production Plant (cont.)			
3					
4	Other Production				
5					
6	340	Land & Land Rights			
7	341	Structures & Improvements			
8	342	Fuel Holders, Producers & Accessories			
9	343	Prime Movers			
10	344	Generators			
11	345	Accessory Electric Equipment			
12	346	Miscellaneous Power Plant Equipment			
13					
14		**TOTAL Other Production Plant**			
15					
16		**TOTAL Production Plant**			
17					
18		**Transmission Plant**			
19					
20	350	Land & Land Rights	20,312	20,312	
21	352	Structures & Improvements			
22	353	Station Equipment			
23	354	Towers & Fixtures			
24	355	Poles & Fixtures	246,308	246,300	0%
25	356	Overhead Conductors & Devices	300,275	300,275	
26	357	Underground Conduit			
27	358	Underground Conductors & Devices			
28	359	Roads & Trails			
29					
30		**TOTAL Transmission Plant**	566,895	566,887	0%
31					
32		**Distribution Plant**			
33					
34	360	Land & Land Rights	5,992	5,992	
35	361	Structures & Improvements	5,970	5,970	
36	362	Station Equipment	410,916	434,705	-5%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	120,717	120,717	
39	365	Overhead Conductors & Devices	109,732	109,732	
40	366	Underground Conduit	909	909	
41	367	Underground Conductors & Devices	15,834	15,834	
42	368	Line Transformers	42,704	42,704	
43	369	Services	3,367	3,367	
44	370	Meters	6,278	6,278	
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	722,419	746,208	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2003

	Account Number & Title	This Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment	14,732	14,732	
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	14,732	14,732	
17				
18	**TOTAL Electric Plant in Service**	1,304,046	1,327,827	

MONTANA DEPRECIATION SUMMARY

Year: 2003

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production				
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production				
6	Transmission	566,887	189,722	150,436	2.12%
7	Distribution	746,208	237,780	250,941	2.78%
8	General	14,732	5,935	5,575	7.18%
9	**TOTAL**	1,327,827	433,437	406,952	12.08%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	N/A		#VALUE!
3	152 Fuel Stock Expenses Undistributed			-
4	153 Residuals			-
5	154 Plant Materials & Operating Supplies:			-
6	Assigned to Construction (Estimated)			-
7	Assigned to Operations & Maintenance			-
8	Production Plant (Estimated)			-
9	Transmission Plant (Estimated)			-
10	Distribution Plant (Estimated)			-
11	Assigned to Other			-
12	155 Merchandise			-
13	156 Other Materials & Supplies			-
14	157 Nuclear Materials Held for Sale			-
15	163 Stores Expense Undistributed			
16				
17	**TOTAL Materials & Supplies**	-	-	-

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	83.4.25			
2	Order Number	4988			
3					
4	Common Equity		52.83%	15.00%	7.92%
5	Preferred Stock		11.96%	9.03%	1.08%
6	Long Term Debt		35.21%	7.75%	2.73%
7	Other				
8	**TOTAL**		100.00%		11.73%
9					
10	Actual at Year End				
11					
12	Common Equity		45.30%		-
13	Preferred Stock				-
14	Long Term Debt		54.70%		-
15	Other				-
16	**TOTAL**		100.00%		-

STATEMENT OF CASH FLOWS

Year: 2003

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	41,177,359	25,994,983	58%
6	Depreciation	17,347,576	18,847,762	-8%
7	Amortization	151,404	355,903	-57%
8	Deferred Income Taxes - Net	4,804,928	8,538,517	-44%
9	Investment Tax Credit Adjustments - Net	(415,957)	(318,304)	-31%
10	Change in Operating Receivables - Net	(3,030,866)	521,267	-681%
11	Change in Materials, Supplies & Inventories - Net	(1,190,378)	181,780	-755%
12	Change in Operating Payables & Accrued Liabilities - Net	2,931,096	(2,283,377)	228%
13	Allowance for Funds Used During Construction (AFUDC)	(571,542)	(44,249)	-1192%
14	Change in Other Assets & Liabilities - Net	3,725,090	(5,446,732)	168%
15	Other Operating Activities (explained on attached page)	(10,960,803)	(1,905,700)	-475%
16	**Net Cash Provided by/(Used in) Operating Activities**	53,967,907	44,441,850	21%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(35,981,400)	(25,382,896)	-42%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets			
23	Investments In and Advances to Affiliates	(45,588,478)	14,798,261	-408%
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	1,221,968	(500,432)	344%
27	**Net Cash Provided by/(Used in) Investing Activities**	(80,347,910)	(11,085,067)	-625%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	75,000,000		#DIV/0!
32	Preferred Stock			
33	Common Stock			
34	Other:			
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(18,041,714)	(3,095,360)	-483%
39	Preferred Stock			
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt			
43	Dividends on Preferred Stock			
44	Dividends on Common Stock	(31,145,914)	(29,727,692)	-5%
45	Other Financing Activities (explained on attached page)			
46	**Net Cash Provided by (Used in) Financing Activities**	25,812,372	(32,823,052)	179%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(567,631)	533,731	-206%
49	**Cash and Cash Equivalents at Beginning of Year**	1,085,479	517,848	110%
50	**Cash and Cash Equivalents at End of Year**	517,848	1,051,579	-51%

LONG TERM DEBT

Year: 2003

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	Series								
2									
3	Y	Jun-88	Jun-18	6,000,000	5,906,578	4,260,000	9.64%	420,020	9.86%
4	Z	May-91	May-21	35,000,000	34,790,305	29,970,000	9.41%	2,874,051	9.59%
5	AA	Jun-91	Sep-03	13,806,000	13,656,287	-	9.10%	50,152	
6	AB	Sep-94	Sep-24	45,000,000	44,243,911	45,000,000	8.44%	3,760,165	8.36%
7	AC	Feb-95	Feb-10	30,000,000	29,766,300	30,000,000	8.12%	2,418,000	8.06%
8	AE	Aug-02	Aug-32	75,000,000	74,008,936	75,000,000	7.23%	5,455,581	7.27%
9									
10									
11	1992 Pollution Control								
12	Revenue Bonds:								
13	Lawrence County SD	Jun-92	Jun-10	5,850,000	5,753,590	5,850,000	6.81%	397,383	6.79%
14	Pennington County SD	Jun-92	Jun-10	2,050,000	1,969,993	2,050,000	6.97%	141,874	6.92%
15	Campbell County WY	Jun-92	Jun-10	1,550,000	1,473,355	1,550,000	7.05%	108,178	6.98%
16	Weston County WY	Jun-92	Jun-10	2,850,000	2,770,414	2,850,000	6.89%	195,451	6.86%
17									
18									
19	1994A Environ Improv B.	Jun-94	Jun-24	3,000,000	2,930,057	2,855,000	4.35%	83,052	2.91%
20	1994 A Construction Fund								
21	1994 Gillette Refund Bond	Jul-94	Jun-24	12,200,000	11,888,427	12,200,000	7.70%	924,750	7.58%
22									
23	Bear Paw Energy Note Payabl	Jun-00	May-12	1,078,000	1,078,000	456,728	13.70%	64,617	14.15%
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			233,384,000	230,236,153	212,041,728		16,893,274	7.97%

PREFERRED STOCK

Year: 2003

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	NONE									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
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28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2003

		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
1	100% of common stock privately held by								
2	the Parent Company								
3	Black Hills Corp.								
4	January	23,416,396							
5									
6	February	23,416,396							
7									
8	March	23,416,396							
9									
10	April	23,416,396							
11									
12	May	23,416,396							
13									
14	June	23,416,396							
15									
16	July	23,416,396							
17									
18	August	23,416,396							
19									
20	September	23,416,396							
21									
22	October	23,416,396							
23									
24	November	23,416,396							
25									
26	December	23,416,396							
27									
28									
29									
30									
31									
32	TOTAL Year End								

MONTANA EARNED RATE OF RETURN

Year: 2003

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service			
3	108 (Less) Accumulated Depreciation			
4	**NET Plant in Service**			
5				
6	Additions			
7	154, 156 Materials & Supplies			
8	165 Prepayments			
9	Other Additions			
10	**TOTAL Additions**			
11				
12	Deductions			
13	190 Accumulated Deferred Income Taxes			
14	252 Customer Advances for Construction			
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions			
17	**TOTAL Deductions**			
18	**TOTAL Rate Base**			
19				
20	**Net Earnings**			
21				
22	**Rate of Return on Average Rate Base**			
23				
24	**Rate of Return on Average Equity**			
25				
26	Major Normalizing Adjustments & Commission			
27	Ratemaking adjustments to Utility Operations			
28				
29	NOTE: This schedule is not completed because			
30	Montana revenues represent less than 1%			
31	of the Company's revenues.			
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	**Adjusted Rate of Return on Average Rate Base**			
48				
49	**Adjusted Rate of Return on Average Equity**			

MONTANA COMPOSITE STATISTICS

Year: 2003

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,328
5	107	Construction Work in Progress	
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(407)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	921
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	660
18			
19	403 - 407	Depreciation & Amortization Expenses	
20		Federal & State Income Taxes	
21		Other Taxes	
22		Other Operating Expenses	
23		TOTAL Operating Expenses	
24			
25		Net Operating Income	660
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	660
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	12
36		Commercial	20
37		Industrial	2
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	34
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	5,708
45		Average Annual Residential Cost per (Kwh) (Cents) *	7.03
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	35
48		Gross Plant per Customer	39,054

MONTANA CUSTOMER INFORMATION

Year: 2003

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties		12	20	2	34
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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30						
31						
32	**TOTAL Montana Customers**		12	20	2	34

Company Name: **Black Hills Power, Inc.** **SCHEDULE 30**

MONTANA EMPLOYEE COUNTS

Year: 2003

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
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45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

Company Name: **Black Hills Power, Inc.**

SCHEDULE 31

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

Year: 2004

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
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48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2003

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	22	1900	317	263,917	83,297
2	Feb.	24	900	328	242,555	73,355
3	Mar.	3	2000	300	258,513	87,047
4	Apr.	30	1300	262	222,203	69,259
5	May	29	1600	316	240,398	81,420
6	Jun.	30	1600	330	241,959	83,324
7	Jul.	24	1400	390	269,901	67,983
8	Aug.	14	1700	391	268,193	65,883
9	Sep.	5	1600	325	227,049	70,994
10	Oct.	31	1800	304	260,766	90,900
11	Nov.	3	1800	303	256,426	83,917
12	Dec.	11	1800	320	259,344	71,327
13	**TOTAL**				3,011,224	928,706

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.					
15	Feb.	*Peak information maintained on a total system basis only.				
16	Mar.					
17	Apr.					
18	May					
19	Jun.					
20	Jul.					
21	Aug.					
22	Sep.					
23	Oct.					
24	Nov.					
25	Dec.					
26	**TOTAL**					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,806,444	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,536,836
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	156,703	for Resale	457,983
7	(Less) Energy for Pumping			
8	**NET Generation**	1,963,147	Non-Requirements Sales	
9	Purchases	1,052,708	for Resale	930,706
10	Power Exchanges			
11	Received	25,666	Energy Furnished	
12	Delivered	(44,551)	Without Charge	
13	**NET Exchanges**	(18,885)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	2,065,490	Electric Utility	7,770
16	Delivered	(2,051,236)		
17	**NET Transmission Wheeling**	14,254	Total Energy Losses	77,929
18	Transmission by Others Losses			
19	**TOTAL**	3,011,224	**TOTAL**	3,011,224

SOURCES OF ELECTRIC SUPPLY

Year: 2003

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	12,687
2					
3	Thermal	Ben French	Rapid City, SD	10	1,040
4					
5	Thermal	Ben French	Rapid City, SD	24	152,316
6					
7	Thermal	Osage	Osage, WY	35	243,721
8					
9	Thermal	Wyodak	Gillette, WY	69	548,310
10					
11	Thermal	Neil Simpson Complex	Gillette, WY	112	862,097
12					
13	Thermal	Neil Simpson Complex	Gillette, WY	39	75,202
14					
15	Thermal	Lange	Rapid City, SD	39	67,774
16					
17	Purchases	See Schedule 33			1,052,708
18					
19	Wheeling	See Schedule 33			14,254
20					
21	Total Interchange	See Schedule 33			(18,885)
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
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34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			426	3,011,224

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2003

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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26							
27							
28							
29							
30							
31							
32	**TOTAL**						

MONTANA CONSUMPTION AND REVENUES

Year: 2003

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$ 5,020	$ 5,243	68	75	12	11
2	Commercial - Small	16,681	18,104	170	183	20	19
3	Commercial - Large	637,833	572,611	14,031	12,817	2	2
4	Industrial - Small						
5	Industrial - Large						
6	Interruptible Industrial						
7	Public Street & Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities						
11	Interdepartmental						
12							
13	**TOTAL**	$ 659,534	$ 595,958	14,269	13,075	34	32