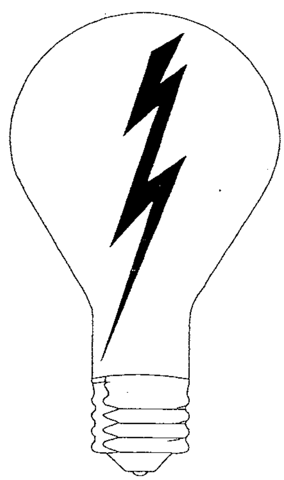
YEAR ENDING 2005

ANNUAL REPORT
OF
BLACK HILLS POWER

ELECTRIC UTILITY



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

2005 Electric Annual Report

Instructions

General

1. A Microsoft EXCEL© workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell. You may also obtain these instructions and the report in both an Adobe Acrobat© format and as an EXCEL© file from our website at **http://psc.mt.gov/**. Please be sure you use the 2005 report form. It has been updated and slightly changed from the 2004 report.

2. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed.

3. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report must be filed. **Please submit one unbound copy of the annual report along with the regular number of annual reports that you submit.** This aids in scanning the report so that it may be published on our web site. The orientation and margins are set up on each individual worksheet and should print on one page.

4. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

5. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

6. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

7. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

8. All companies owned by another company shall attach a corporate structure chart of the holding company.

9. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

Schedules 1 through 5
Schedules 6 and 7
Schedule 14
Schedule 17 and 18
Schedules 23 through 26
Schedules 33 and 34

11. All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

12. Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

13. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedule.

14. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and 132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

3. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 32

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 34

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.
   Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages exceeding one hour which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 35

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Schedule 35a

1. Contracted or committed current year expenditures include those expenditures that derive from preexisting contracts or commitments related to current year program activity but which will actually occur in a year other than the current year.

2. Expected average annual bill savings from weatherization should reflect average household bill savings based on the total households weatherized and the combined savings of all weatherization measures installed.

Company Name: **Black Hills Power, Inc.** **SCHEDULE 1**

IDENTIFICATION

Year: **2005**

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	David R. Emery (a)	Rapid City, SD	
2	Thomas J. Zeller	Rapid City, SD	55,333
3	John R. Howard	Rapid City, SD	61,333
4	Kay S. Jorgensen	Spearfish, SD	50,633
5	David C. Ebertz	Gillette, WY	47,833
6	Richard Korpan	Evergreen, CO	50,333
7	Stephen D. Newlin	Avon Lake, OH	44,333
8	Jack W. Eugster	Excelsior, MN	43,083
9	William G. Van Dyke (b)	Edina, MN	31,333
10	John B. Vering (b)	Southlake, TX	31,333
11	Bruce B. Brundage ©	Englewood, CO	359,913
12			
13	(a) Officer of the Company and not compensated as a Director		
14	(b) Elected to the Board of Directors May 2005		
15	© Retired from the Board of Directors May 2005		
16			
17			
18			
19			
20			

BLACK HILLS CORPORATION ORGANIZATIONAL CHART

July 1, 2005

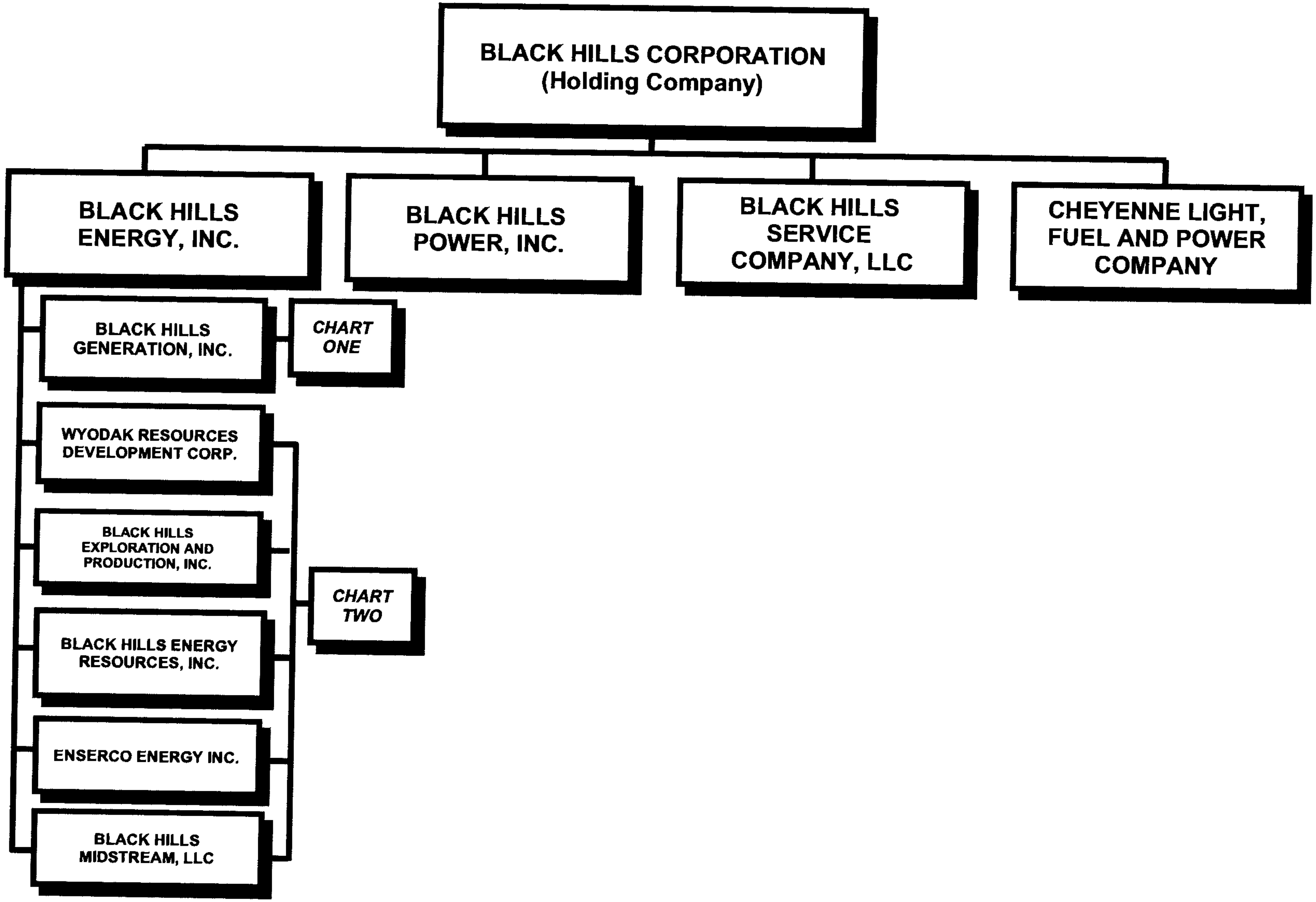


Chart One
July 15, 2005

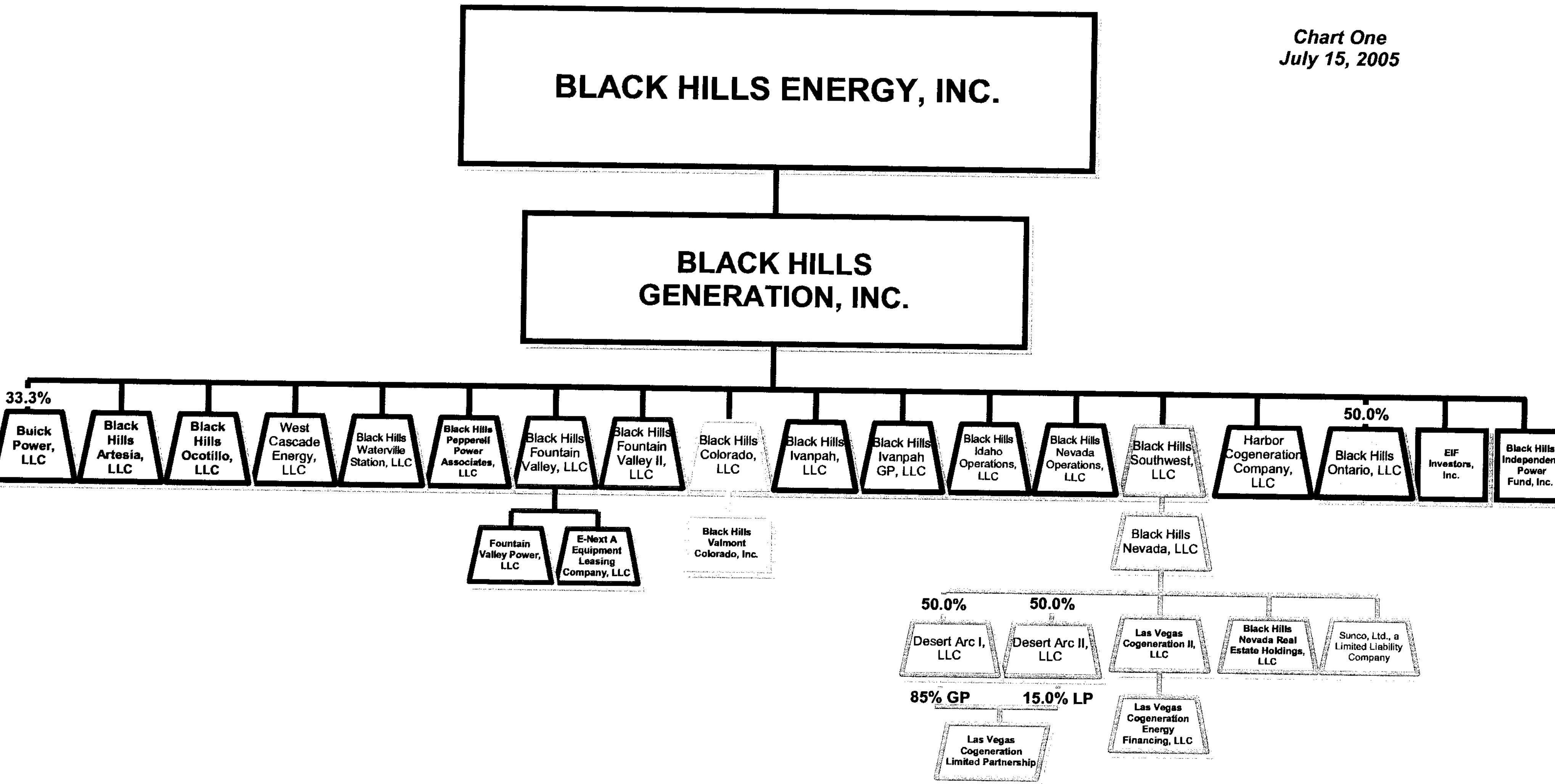
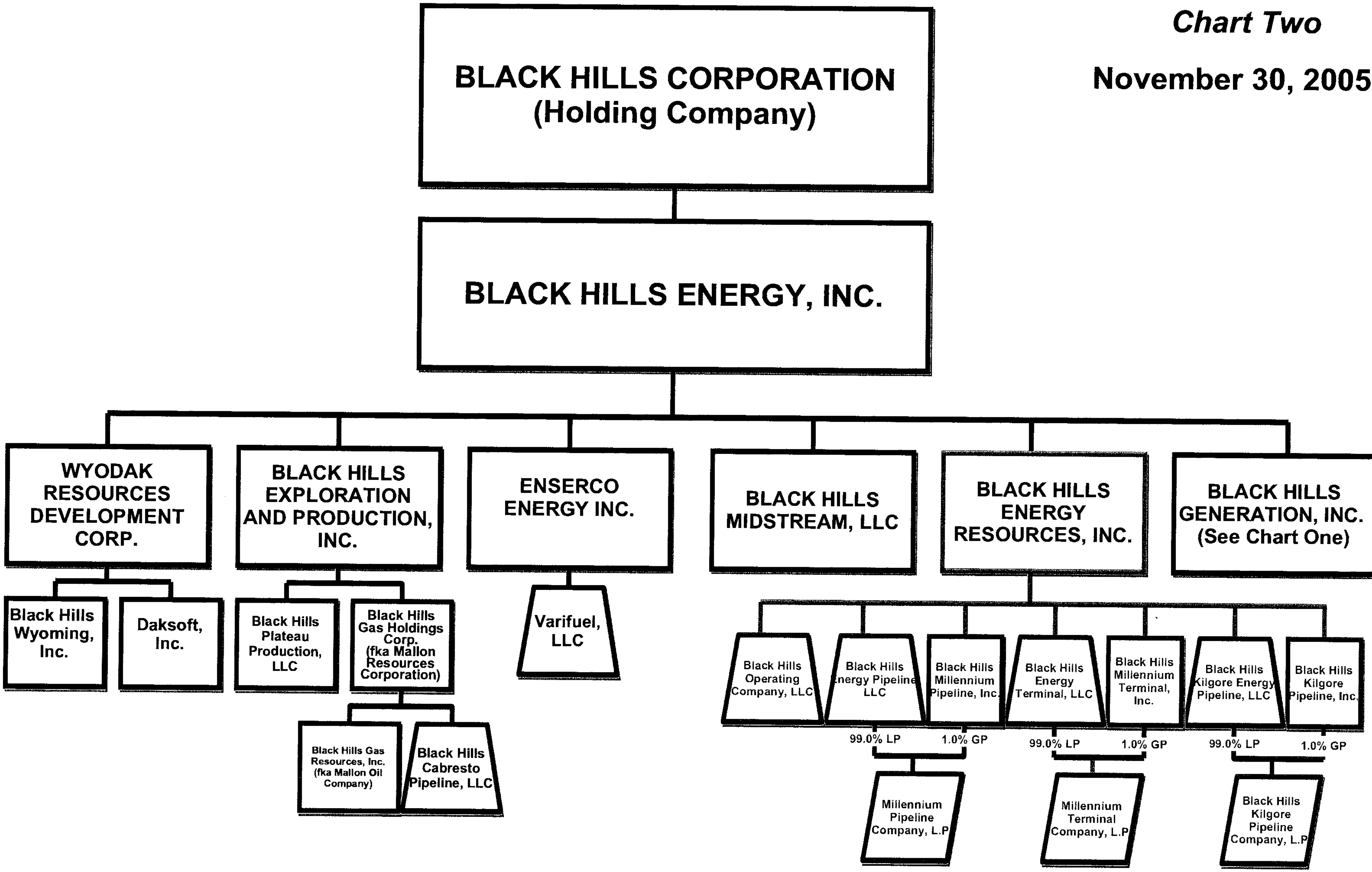


Chart Two

November 30, 2005



Company Name: Black Hills Power, Inc. **SCHEDULE 3**

Officers

Year: 2005

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman and Chief Executive Officer		David R. Emery
2			
3	President and Chief Operating Officer		Linden R. Evans
4			
5	Exec. V.P., Chief Financial Officer		Mark T. Thies
6			
7	Senior V.P., General Counsel		Steven J. Helmers
8			
9	Senior V.P., Corporate Administration		James M. Mattern
10			
11	Senior V.P. and Chief Risk Officer		Russell L. Cohen
12			
13	Senior V.P., Strategic Planning and Dev		Maurice T. Klefeker
14			
15	Vice President - Operations		Stuart A. Wevik
16			
17	Vice President - Power Delivery		Mark L. Lux
18			
19	Vice President - Governance & Corporate Secretary		Roxann R. Basham
20			
21	Vice President and Corporate Controller		Perry S. Krush
22			
23	Vice President and Treasurer		Garner M. Anderson
24			
25	Vice President - Corporate Affairs		Kyle D. White
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			

CORPORATE STRUCTURE

Year: 2005

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc	Electric Utility	18,005,352	100.00%
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				100.00%
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL**		18,005,352	

Company Name: Black Hills Power, Inc.

SCHEDULE 5

CORPORATE ALLOCATIONS

Year: 2005

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Not significant to Montana Operations					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2005

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	10,056,152	29.34%	87,489
2	Development Corp		similar arms-length transactions)			
3						
4	Enserco Energy, Inc.	Gas sales to Utility	Fair Market Value (Based on	6,360,772	0.17%	55,339
5			similar arms-length transactions)			
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	TOTAL			16,416,924		142,828

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2005

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	659,200	100.00%	
3						
4	Black Hills Wyoming	Transmission Service	Point-to-Point			
5			Open Access Transmission Tariff	509,277	100.00%	
6						
7	Black Hills Wyoming	Non-firm energy sales	Fair Market Value (Based on	1,942,539	100.00%	
8			similar arms-length transactions)			
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL**			3,111,016		

MONTANA UTILITY INCOME STATEMENT

Year: 2005

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	173,744,544	189,005,406	8.78%
2					
3		Operating Expenses			
4	401	Operation Expenses	94,395,337	117,930,059	24.93%
5	402	Maintenance Expense	8,773,623	8,116,142	-7.49%
6	403	Depreciation Expense	18,721,971	19,391,889	3.58%
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	7,794,661	7,260,750	-6.85%
12	409.1	Income Taxes - Federal	5,731,341	8,301,378	44.84%
13		- Other			
14	410.1	Provision for Deferred Income Taxes	5,188,756	134,426	-97.41%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(1,128,557)	(2,432,494)	-115.54%
16	411.4	Investment Tax Credit Adjustments	(279,115)	(260,327)	6.73%
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**	139,349,421	158,593,227	13.81%
21		**NET UTILITY OPERATING INCOME**	34,395,123	30,412,179	-11.58%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	5,484	6,091	11.07%
3	442	Commercial & Industrial - Small	13,972	16,193	15.90%
4		Commercial & Industrial - Large	758,705	836,795	10.29%
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**	778,161	859,079	10.40%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	778,161	859,079	10.40%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	778,161	859,079	10.40%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	345	(47)	-113.62%
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**	345	(47)	-113.62%
26		**Total Electric Operating Revenues**	778,506	859,032	10.34%

(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.

Regulatory Accounting

The Company's regulated electric operations are 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).

The Company's electric operations follow 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. If rate recovery 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 4.2 percent and 9.8 percent during 2005 and 2004, 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 rate of 3.0 percent in 2005 and 3.0 percent in 2004.

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 uncollectible accounts receivable, long-lived asset values and useful lives, employee benefits plans and contingencies. Actual results could differ from those estimates.

Cash Equivalents

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

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are generally stated at cost on a weighted-average basis. To the extent fuel has been designated as the underlying hedged item in a "fair value" hedge transaction, those volumes are stated at market value using published industry quotations. As of December 31, 2005, market adjustments related to fuel were $(0.2) million.

Deferred Financing Costs

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

Derivatives and Hedging Activities

The Company, from time to time, utilizes risk management contracts including forward purchases and sales and fixed-for-float swaps to hedge the price of fuel for its combustion turbines, maximize the value of its natural gas storage or to fix the interest on its variable rate debt. Certain of the contracts qualify as derivatives under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). SFAS 133 requires 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 qualifying 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, is recognized currently in earnings.

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 2005 or 2004.

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.

Revenue Recognition

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.

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 1 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.

Supplemental Disclosure of Cash Flow Information

Cash paid during the year 2005 for interest was $11,993,000 and cash paid during the year 2005 for income taxes was $5,295,000.

(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 2006 through 2009, and $32.0 million for the year 2010.

(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 debt instruments having similar maturities and similar debt ratings. The Company's outstanding first mortgage 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 first mortgage bonds.

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

	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 157,215	$ 183,491	$ 159,206	$ 190,273

(5) JOINTLY OWNED FACILITIES

The Company uses the proportionate consolidation method to account for its percentage interest in the assets, liabilities and expenses of the following 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, 2005, the Company's investment in the Plant included $73.8 million in electric plant and $38.8 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Balance Sheets. The Company's share of direct expenses of the Plant was $6.1 million and $6.0 million for the years ended December 31, 2005 and 2004, 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. The Company's share of direct expenses was $0.2 and $0.1 million for years ended December 31, 2005 and 2004, respectively. As of December 31, 2005, the Company's investment in the transmission tie was $19.7 million, with $0.9 million of accumulated depreciation and is included in the corresponding captions in the accompanying Balance Sheets.

(6) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements – Pacific Power

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 $10.1 million in 2005 and $10.0 million in 2004.

In addition, the Company has a firm network transmission agreement for 36 megawatts 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 $0.4 million in 2005 and $0.4 million in 2004.

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 contract expires in February 2013.

- The Company has a contract with Montana-Dakota Utilities Company, expiring January 1, 2007, for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory. The Company entered into a new power purchase agreement with MDU for the supply of up to 74 megawatts of capacity and energy for Sheridan, Wyoming from 2007 through 2016, which is subject to regulatory approval by the WPSC. 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. The agreement renews automatically and requires a seven-year notice of termination. Both contracts are served by the Company and are integrated into its control area and are treated as part of the Company's 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. A trial date has been set for late 2006. 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 has been 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 completed its own investigation of the fire cause and origin and 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. A trial date has been set for August 2006. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April 2003 through June 2005, 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, all arising from the Grizzly Gulch Fire. A trial date has been set for August 2006.

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 a 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 filed its Response to Demand, including a counterclaim that seeks recovery of sums PPM has refused to pay pursuant to the Exchange Agreement. The Company denies all claims. The dispute was presented to the arbitrator in August 2005. The Company cannot predict the outcome of the decision.

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. The Company uses a September 30 measurement date for the Plan.

Obligations and Funded Status

Change in benefit obligation:

	2005	2004
	(in thousands)	
Projected benefit obligation at beginning of year	$ 46,176	$ 44,803
Service cost	991	959
Interest cost	2,700	2,621
Actuarial (gain) loss	9	(182)
Discount rate change	1,630	—
Benefits paid	(2,122)	(2,025)
Asset transfer to affiliate	(592)	—
Mortality assumption change	519	—
Net increase	3,135	1,373
Projected benefit obligation at end of year	$ 49,311	$ 46,176

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

	2005	2004
	(in thousands)	
Beginning market value of plan assets	$ 39,844	$ 37,115
Benefits paid	(2,122)	(2,025)
Investment income	6,729	4,754
Asset transfer to affiliate	(592)	—
Ending market value of plan assets	$ 43,859	$ 39,844

Funding information for the Plan is as follows:

	2005	2004
	(in thousands)	
Fair value of plan assets	$ 43,859	$ 39,844
Projected benefit obligation	(49,311)	(46,176)
Funded status	(5,452)	(6,332)
Unrecognized:		
Net loss	12,915	14,860
Prior service cost	766	922
	13,681	15,782
Net amount recognized	$ 8,229	$ 9,450

Amounts recognized in statement of financial position consist of:

	2005	2004
	(in thousands)	
Net pension asset	$ 8,229	$ 9,450
Accumulated benefit obligation	$ 41,191	$ 38,302

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of $8.2 million and $9.5 million at December 31, 2005 and 2004, respectively and is included in the line item Other in Other assets on the accompanying Balance Sheets.

Components of Net Periodic Pension Expense

	2005	2004
	(in thousands)	
Service cost	$ 991	$ 959
Interest cost	2,700	2,621
Expected return on assets	(3,480)	(3,420)
Amortization of prior service cost	156	166
Recognized net actuarial loss	854	1,080
Net pension expense	$ 1,221	$ 1,406

Assumptions

Weighted-average assumptions used to determine benefit obligations:	2005	2004
Discount rate	5.75%	6.00%
Rate of increase in compensation levels	4.34%	4.39%
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2005	2004
Discount rate	6.00%	6.00%
Expected long-term rate of return on assets*	9.00%	9.50%
Rate of increase in compensation levels	4.39%	5.00%

* The expected rate of return on plan assets was changed from 9.00 percent in 2005 to 8.50 percent for the calculation of the 2006 net periodic pension cost. This change is expected to increase pension costs in 2006 by approximately $0.3 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 9.5 percent and 10.0 percent for the 2005 and 2004 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, 2005, 11.8 percent, 12.5 percent, 10.1 percent and 10.3 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 10-year treasury bonds of 7.0 percent from 1962 to 2005, and adjusted for recent declines in interest rates. 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:

	2005	2004
Domestic equity	52.9%	59.7%
Foreign equity	40.6	34.5
Fixed income	3.4	2.6
Cash	3.1	3.2
Total	100.0%	100.0%

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

Asset Class	Target Allocation*
US Stocks	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 has been modified for 2006 to target an allocation of 50 percent U.S. stock, 25 percent foreign stock and 25 percent fixed income.

The Plan's investment policy includes the investment objective that the achieved long-term rates 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.

Cash Flows

The Company does not anticipate any employer contributions to the Plan in 2006.

Estimated Future Benefit Payments

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

2006	$	2,163
2007		2,215
2008		2,303
2009		2,406
2010		2,558
2011-2015		14,763

Supplemental Nonqualified Defined Benefit Retirement Plans

The Company has various supplemental retirement plans for 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

		2005		2004
		(in thousands)		
Change in benefit obligation:				
Projected benefit obligation at beginning of year	$	1,886	$	1,886
Service cost		—		—
Interest cost		110		110
Actuarial (gains) losses		143		(8)
Benefits paid		(117)		(102)
Net increase		136		—
Projected benefit obligation at end of year	$	2,022	$	1,886
Fair value of plan assets at end of year	$	—	$	—
Funded status		(2,022)		(1,886)
Unrecognized net loss		858		762
Unrecognized prior service cost		3		3
Contributions		25		36
Net amount recognized	$	(1,136)	$	(1,085)

		2005		2004
		(in thousands)		
Amounts recognized in statement of financial position consist of:				
Net pension liability	$	(1,785)	$	(1,650)
Intangible asset		3		3
Contributions		26		36

Accumulated other comprehensive loss		620		526
Net amount recognized	$	(1,136)	$	(1,085)
Accumulated benefit obligation	$	1,785	$	1,650

The provisions of SFAS 87 required the Company to record an accrued pension liability of $1.8 million and $1.7 million at December 31, 2005 and 2004, respectively, and is included in Deferred credits and other liabilities, Other on the accompanying Balance Sheets.

Components of Net Periodic Benefit Cost

		2005		2004
		(in thousands)		
Service cost	$	—	$	—
Interest cost		109		110
Amortization of prior service cost		1		1
Recognized net actuarial loss		48		53
Net periodic benefit cost	$	158	$	164

Additional Information

		2005		2004
		(in thousands)		
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$	94	$	25

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2005	2004
Discount rate	5.75%	6.00%
Rate of increase in compensation levels	5.00%	5.00%
Weighted-average assumptions used to determine net periodic benefit cost for plan year	2005	2004
Discount rate	6.00%	6.00%
Rate of increase in compensation levels	5.00%	5.00%

Plan Assets

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

Estimated Cash Flows

The estimated employer contribution is expected to be $0.1 million in 2006.

The following benefit payments, which reflect expected future service, are expected to be paid (in thousands):

Fiscal Year Ending		
2006	$	103
2007		109
2008		125
2009		112
2010		115
2011-2015		458

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.

It has been determined that the Plan's post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy.

The effect on the accumulated postretirement benefit obligation for the fiscal year ending December 31, 2005, was an actuarial gain of approximately $1.1 million. The effect on 2006 net periodic postretirement benefit cost will be a decrease of approximately $0.1 million.

Obligation and Funded Status

		2005		2004
		(in thousands)		
Change in benefit obligation:				
Accumulated postretirement benefit obligation at beginning of year	$	7,861	$	8,197
Service cost		292		300
Interest cost		465		485
Plan participants' contributions		403		339
Benefits paid and actual expenses		(469)		(516)
Net transfer out		(26)		—
Medicare Part D subsidy		(1,126)		—
Actuarial gains		(233)		(944)
Net decrease		(694)		(336)
Accumulated postretirement benefit obligation at end of year	$	7,167	$	7,861
Fair value of plan assets at end of year	$	—	$	—
Funded status		(7,167)		(7,861)

Unrecognized net loss		409		1,842
Unrecognized prior service cost		(208)		(227)
Unrecognized transition obligation		817		934
Contributions		13		23
Net amount recognized	$	(6,136)	$	(5,289)

Amounts recognized in statement of financial position consist of:

		2005		2004
		(in thousands)		
Accrued postretirement liability	$	(6,136)	$	(5,289)

Components of Net Periodic Benefit Cost

		2005		2004
		(in thousands)		
Service cost	$	292	$	300
Interest cost		465		486
Amortization of transition obligation		117		116
Amortization of prior service cost		(19)		(19)
Recognized net actuarial loss		74		144
Net periodic benefit cost	$	929	$	1,027

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30		
	2005	2004
Discount rate	5.75%	6.00%
Weighted-average assumptions used to determine net periodic benefit cost for plan year		
	2005	2004
Discount rate	6.00%	6.00%

The healthcare trend rate assumption for the 2005 fiscal year benefit obligation determination and 2006 fiscal year expense is 11 percent for 2005 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011. The healthcare cost trend rate assumption for the 2004 fiscal year benefit obligation determination and 2005 fiscal year expense was 12 percent for 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 $0.2 million or 23 percent and the accumulated periodic postretirement benefit obligation $1.3 million or 18 percent. A 1 percent decrease would reduce the service and interest cost by $0.1 million or 18 percent and the accumulated periodic postretirement benefit obligation $1.0 million or 15 percent.

Plan Assets

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

Estimated Cash Flows

The estimated employer contribution is expected to be $0.2 million in 2006.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, are expected to be paid (in thousands):

Fiscal Year Ending	Expected Gross Benefit Payment	Expected Medicare Part D (Prescription Drug Benefit) Subsidy	Expected Net Benefit Payments
2006	$ 227	$ (24)	$ 203
2007	250	(27)	223
2008	267	(31)	236
2009	303	(34)	269
2010	354	(36)	318
2011 - 2015	2,136	(236)	1,900

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 approximately $0.5 million for 2005 and $0.4 million for 2004.

(8) INCOME TAXES

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

	2005	2004
Current	$ 8,301	$ 5,731
Deferred	(2,558)	3,781
	$ 5,743	$ 9,512

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

Years ended December 31,		2005		2004
Deferred tax assets, current:				
Asset valuation reserve	$	291	$	319
Employee benefits		550		382
Items of other comprehensive income		76		—
Other		110		157
		1,027		858
Deferred tax liabilities, current:				
Prepaid expenses		192		155
Net deferred tax asset, current	$	835	$	703
Deferred tax assets, non-current:				
Plant related differences	$	949	$	598
Regulatory asset		898		1,025
ITC		271		362
Employee benefits		2,929		2,602
Items of other comprehensive income		217		184
Other		204		213
		5,468		4,984
Deferred tax liabilities, non-current:				
Accelerated depreciation and other plant related differences		65,459		66,371
AFUDC		2,640		2,712
Regulatory liability		1,422		1,460
Employee benefits		2,880		3,307
Items of other comprehensive income		—		22
Other		1,009		1,050
		73,410		74,922
Net deferred tax liability, non-current	$	67,942	$	69,938
Net deferred tax liability	$	67,107	$	69,235

The following table reconciles the change in the net deferred income tax liability from December 31, 2004, to December 31, 2005, to the deferred income tax benefit (in thousands):

		2005
Decrease in deferred income tax liability from the preceding table	$	(2,128)
Deferred taxes associated with ITC		(517)
Deferred taxes associated with other comprehensive loss		87
Deferred income tax benefit for the period	$	(2,558)

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

	2005	2004
Federal statutory rate	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(1.7)	(1.5)
Deferred tax adjustments primarily related to plant-related changes in estimate	(8.2)	—
Research and development credit	—	—
Other	(0.9)	(0.4)
	24.2%	33.1%

(9) 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):

	2005		
	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Minimum pension liability adjustment	$ (94)	$ 33	$ (61)
Amortization of cash flow hedges settled and deferred in accumulated other comprehensive income (loss) and reclassified into interest expense	64	(22)	42
Net change in fair value of derivatives designated as cash flow hedges	(219)	76	(143)
Other comprehensive loss	$ (249)	$ 87	$ (162)

	2004		
	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Minimum pension liability adjustment	$ 25	$ (9)	$ 16
Amortization of cash flow hedges settled and deferred in accumulated other comprehensive income (loss) and reclassified into interest expense	64	(22)	42
Other comprehensive income	$ 89	$ (31)	$ 58

(10) RELATED-PARTY TRANSACTIONS

Receivables and Payables

The Company has accounts receivable balances related to transactions with other Black Hills Corporation subsidiaries. The balances were $2.0 million and $0.9 million as of December 31, 2005 and 2004, respectively. The Company also has accounts payable balances related to transactions with other Black Hills Corporation subsidiaries. The balances were $1.6 million and $0.3 million as of December 31, 2005 and 2004, respectively.

Notes Payable - Affiliate

The Company has borrowings from its Parent, which are due on demand. Outstanding advances were $1.8 million at December 31, 2005 and $25.1 million at December 31, 2004. Advances under this note bear interest at 0.70 percent above the daily LIBOR rate (5.09 percent at December 31, 2005). Interest paid was $0.8 million and $0.1 million for the years ended December 31, 2005 and 2004, respectively.

In August 2005, the Company entered into a Utility Money Pool Agreement with the Parent; and Cheyenne Light, Fuel & Power, an electric and gas utility subsidiary of the Parent.

Under the agreement, the Company may borrow from the Parent. The Agreement restricts the Company from loaning funds to the Parent or to any of the Parent's non-utility subsidiaries; the Agreement does not restrict the Company from making dividends to the Parent. Borrowings under the Agreement bear interest at the daily cost of external funds as defined under the Agreement, or if there are no external funds outstanding on that date, then the rate will be the daily one-month LIBOR rate plus 100 basis points.

Other Balances and Transactions

The Company purchases coal from Wyodak Resources Development Corp., an indirect subsidiary of the Parent. The amount purchased during the years ended December 31, 2005 and 2004 was $10.1 million and $9.6 million, respectively.

In addition to the above transactions, in order to fuel its combustion turbine, the Company purchased natural gas from Enserco Energy, an indirect subsidiary of the Parent. The amount purchased during the years ended December 31, 2005 and 2004 was approximately $6.4 million and $2.7 million, respectively. These amounts are included in "Fuel and purchased power" on the Statements of Income.

The Company also received revenues of approximately $2.2 million and $1.1 million for the years ended December 31, 2005 and 2004, respectively, from Black Hills Wyoming, Inc., an indirect subsidiary of Black Hills Corporation, for the transmission of electricity.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2005

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,002,044	1,045,237	4.31%
6	501 Fuel	12,933,902	13,622,030	5.32%
7	502 Steam Expenses	2,741,998	2,583,945	-5.76%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	846,233	915,234	8.15%
11	506 Miscellaneous Steam Power Expenses	1,247,851	1,354,053	8.51%
12	507 Rents			
13				
14	TOTAL Operation - Steam	18,772,028	19,520,499	3.99%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	283,067	293,080	3.54%
18	511 Maintenance of Structures	180,496	174,509	-3.32%
19	512 Maintenance of Boiler Plant	3,287,080	2,973,011	-9.55%
20	513 Maintenance of Electric Plant	1,755,761	1,655,611	-5.70%
21	514 Maintenance of Miscellaneous Steam Plant	576,246	571,422	-0.84%
22				
23	TOTAL Maintenance - Steam	6,082,650	5,667,633	-6.82%
24				
25	**TOTAL Steam Power Production Expenses**	24,854,678	25,188,132	1.34%
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: 2005

	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	69,445	62,753	-9.64%
27	547	Fuel	2,214,762	3,228,660	45.78%
28	548	Generation Expenses	304,141	326,906	7.49%
29	549	Miscellaneous Other Power Gen. Expenses	22,838	35,276	54.46%
30	550	Rents	9,223		-100.00%
31					
32		TOTAL Operation - Other	2,620,409	3,653,595	39.43%
33					
34	Maintenance				
35	551	Maintenance Supervision & Engineering	96,556	127,007	31.54%
36	552	Maintenance of Structures	6,757	13,600	101.27%
37	553	Maintenance of Generating & Electric Plant	844,714	214,028	-74.66%
38	554	Maintenance of Misc. Other Power Gen. Plant	9,136	12,000	31.35%
39					
40		TOTAL Maintenance - Other	957,163	366,635	-61.70%
41					
42		**TOTAL Other Power Production Expenses**	3,577,572	4,020,230	12.37%
43					
44	Other Power Supply Expenses				
45	555	Purchased Power	46,329,877	62,983,896	35.95%
46	556	System Control & Load Dispatching			
47	557	Other Expenses			
48					
49		TOTAL Other Power Supply Expenses	46,329,877	62,983,896	35.95%
50					
51		**TOTAL Power Production Expenses**	74,762,127	92,192,258	23.31%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2005

	Account Number & Title		Last Year	This Year	% Change
1	Transmission Expenses				
2	Operation				
3	560	Operation Supervision & Engineering	246,161	357,602	45.27%
4	561	Load Dispatching	677,982	741,059	9.30%
5	562	Station Expenses	84,284	182,214	116.19%
6	563	Overhead Line Expenses	49,442	68,731	39.01%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	2,258,619	2,458,614	8.85%
9	566	Miscellaneous Transmission Expenses	161,709	187,975	16.24%
10	567	Rents			
11					
12	TOTAL Operation - Transmission		3,478,197	3,996,195	14.89%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	42,197	27,858	-33.98%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	87,515	88,187	0.77%
17	571	Maintenance of Overhead Lines	224,898	145,193	-35.44%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21	TOTAL Maintenance - Transmission		354,610	261,238	-26.33%
22					
23	**TOTAL Transmission Expenses**		3,832,807	4,257,433	11.08%
24					
25	Distribution Expenses				
26	Operation				
27	580	Operation Supervision & Engineering	544,632	553,852	1.69%
28	581	Load Dispatching	117,473	68,144	-41.99%
29	582	Station Expenses	281,800	331,405	17.60%
30	583	Overhead Line Expenses	576,855	680,992	18.05%
31	584	Underground Line Expenses	212,075	202,086	-4.71%
32	585	Street Lighting & Signal System Expenses	3,802	954	-74.91%
33	586	Meter Expenses	454,789	472,697	3.94%
34	587	Customer Installations Expenses	38,718	33,931	-12.36%
35	588	Miscellaneous Distribution Expenses	352,077	388,190	10.26%
36	589	Rents	23,040	21,599	-6.25%
37					
38	TOTAL Operation - Distribution		2,605,261	2,753,850	5.70%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	22,733	21,236	-6.59%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	80,178	47,440	-40.83%
43	593	Maintenance of Overhead Lines	763,814	1,210,067	58.42%
44	594	Maintenance of Underground Lines	103,221	115,557	11.95%
45	595	Maintenance of Line Transformers	10,637	17,811	67.44%
46	596	Maintenance of Street Lighting, Signal Systems	101,301	114,705	13.23%
47	597	Maintenance of Meters	48,058	43,637	-9.20%
48	598	Maintenance of Miscellaneous Dist. Plant	59,226	36,730	-37.98%
49					
50	TOTAL Maintenance - Distribution		1,189,168	1,607,183	35.15%
51					
52	**TOTAL Distribution Expenses**		3,794,429	4,361,033	14.93%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2005

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	32,181	14,640	-54.51%
4	902 Meter Reading Expenses	407,334	420,232	3.17%
5	903 Customer Records & Collection Expenses	909,031	835,604	-8.08%
6	904 Uncollectible Accounts Expenses	189,263	41,154	-78.26%
7	905 Miscellaneous Customer Accounts Expenses	515,837	456,429	-11.52%
8				
9	TOTAL Customer Accounts Expenses	2,053,646	1,768,059	-13.91%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	67,210	72,404	7.73%
14	908 Customer Assistance Expenses	779,870	751,127	-3.69%
15	909 Informational & Instructional Adv. Expenses	5,847	5,092	-12.91%
16	910 Miscellaneous Customer Service & Info. Exp.	76,826	64,747	-15.72%
17				
18	TOTAL Customer Service & Info Expenses	929,753	893,370	-3.91%
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	4,384,438	7,472,130	70.42%
32	921 Office Supplies & Expenses	2,581,089	737,225	-71.44%
33	922 (Less) Administrative Expenses Transferred - Cr.	(57,051)	(58,002)	-1.67%
34	923 Outside Services Employed	5,034,383	8,725,919	73.33%
35	924 Property Insurance	850,133	602,294	-29.15%
36	925 Injuries & Damages	1,281,703	1,125,196	-12.21%
37	926 Employee Pensions & Benefits	2,806,960	2,901,973	3.38%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	195,565	297,625	52.19%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	121,741	164,721	35.30%
42	930.2 Miscellaneous General Expenses	195,111	197,660	1.31%
43	931 Rents	212,094	193,854	-8.60%
44				
45	TOTAL Operation - Admin. & General	17,606,166	22,360,595	27.00%
46	Maintenance			
47	935 Maintenance of General Plant	190,033	213,453	12.32%
48				
49	**TOTAL Administrative & General Expenses**	17,796,199	22,574,048	26.85%
50				
51	**TOTAL Operation & Maintenance Expenses**	103,168,961	126,046,201	22.17%

MONTANA TAXES OTHER THAN INCOME

Year: 2005

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel			
5	Montana PSC	1,274	4,879	282.97%
6	Franchise Taxes			
7	Property Taxes	71,682	49,785	-30.55%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	2,736	2,496	-8.77%
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51	**TOTAL MT Taxes Other Than Income**	75,692	57,160	-24.48%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2005

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts to Montana Are Not Significant				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	**TOTAL Payments for Services**				

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2005

	Description	Total Company	Montana	% Montana
1	NONE			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2005

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	46,176,270	44,803,319	-2.97%
8	Service cost	991,297	958,523	-3.31%
9	Interest Cost	2,700,217	2,621,330	-2.92%
10	Plan participants' contributions			
11	Amendments-Asset Transfer,Discount rate, mortality	1,556,488		-100.00%
12	Actuarial Gain	8,988	(182,135)	-2126.42%
13	Acquisition			
14	Benefits paid	(2,121,869)	(2,024,767)	4.58%
15	Benefit obligation at end of year	49,311,391	46,176,270	-6.36%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	39,843,830	37,115,057	-6.85%
18	Actual return on plan assets	6,728,814	4,753,540	-29.36%
19	Acquisition			
20	Employer contribution			
21	Asset Transfers	(591,869)		100.00%
22	Benefits paid	(2,121,869)	(2,024,767)	4.58%
23	Fair value of plan assets at end of year	43,858,906	39,843,830	-9.15%
24	**Funded Status**	(5,452,485)	(6,332,440)	-16.14%
25	Unrecognized net actuarial loss	12,915,382	14,859,973	15.06%
26	Unrecognized prior service cost	766,466	922,428	20.35%
27	Prepaid (accrued) benefit cost	8,229,363	9,449,961	14.83%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	6.00%	6.00%	
31	Expected return on plan assets	9.00%	9.50%	5.56%
32	Rate of compensation increase	4.39%	5.00%	13.90%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	991,297	958,523	-3.31%
36	Interest cost	2,700,217	2,621,330	-2.92%
37	Expected return on plan assets	(3,480,406)	(3,420,054)	1.73%
38	Amortization of prior service cost	155,962	165,460	6.09%
39	Recognized net actuarial loss	853,528	1,081,386	26.70%
40	Net periodic benefit cost	1,220,598	1,406,645	15.24%
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	860	836	-2.79%
48	Not Covered by the Plan	38	33	-13.16%
49	Active	501	487	-2.79%
50	Retired	168	169	0.60%
51	Deferred Vested Terminated	153	147	-3.92%

Other Post Employment Benefits (OPEBS)

Year: 2005

	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	6.00%	6.00%	
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	11.00%	12.00%	9.09%
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase	4.39%	5.00%	13.90%
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	5,289,609	4,420,606	-16.43%
20	Service cost	292,280	299,742	2.55%
21	Interest Cost	465,329	485,520	4.34%
22	Plan participants' contributions			
23	Amendments			
24	Actuarial Gain	171,525	241,723	40.93%
25	Acquisition			
26	Benefits paid	(82,388)	(157,982)	-91.75%
27	Benefit obligation at end of year	6,136,355	5,289,609	-13.80%
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**	(6,136,355)	(5,289,609)	13.80%
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost	(6,136,355)	(5,289,609)	13.80%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	292,280	299,742	2.55%
42	Interest cost	465,329	485,520	4.34%
43	Expected return on plan assets			
44	Amortization of prior service cost			
45	Recognized net actuarial loss	171,525	241,723	40.93%
46	Net periodic benefit cost	929,134	1,026,985	10.53%
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			

Other Post Employment Benefits (OPEBS) Continued

Year: 2005

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	703	689	-1.99%
3	Not Covered by the Plan			
4	Active	496	480	-3.23%
5	Retired	110	113	2.73%
6	Spouses/Dependants covered by the Plan	97	96	-1.03%
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			

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	David R. Emery Chairman and Chief Executive Officer	475,000		277,153	752,153	654,638	15%
2	Mark T. Thies Senior Vice President and Chief Financial Officer	269,100		545,577	814,677	461,942	76%
3	Roxann R. Basham Vice President - Governance and Corporate Secretary	166,812		467,868	634,680	222,436	185%
4	James M. Mattern Vice President - Corporate Administration	213,608		254,586	468,194	315,210	49%
5	Kyle D. White Vice President - Corporate Affairs	163,681		247,443	411,124	212,662	93%

BALANCE SHEET

Year: 2005

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	607,392,736	638,453,677	-5%
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	28,441,912	10,810,779	163%
9	107 Construction Work in Progress - Electric	4,065,626	6,684,274	-39%
10	108 (Less) Accumulated Depreciation	(240,472,137)	(258,537,572)	7%
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.	(2,069,191)	(2,220,595)	7%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	402,229,254	400,060,871	1%
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			
22	124 Other Investments	3,395,292	3,522,069	-4%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	3,396,954	3,523,731	-4%
25				
26	**Current & Accrued Assets**			
27	131 Cash	3,410,024	679,981	401%
28	132-134 Special Deposits			
29	135 Working Funds	3,400	4,625	-26%
30	136 Temporary Cash Investments	133,399		#DIV/0!
31	141 Notes Receivable		63,063	-100%
32	142 Customer Accounts Receivable	13,447,835	14,992,893	-10%
33	143 Other Accounts Receivable	1,264,005	995,560	27%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(911,537)	(830,090)	-10%
35	145 Notes Receivable - Associated Companies			
36	146 Accounts Receivable - Associated Companies	890,550	1,964,490	-55%
37	151 Fuel Stock	2,210,658	3,991,733	-45%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	9,302,453	10,244,358	-9%
41	155 Merchandise			
42	156 Other Material & Supplies	(174)	(447)	61%
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed			
45	165 Prepayments	11,765,887	8,794,608	34%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	4,383,846	4,928,488	-11%
49	174 Miscellaneous Current & Accrued Assets	29,838	191,680	-84%
50	**TOTAL Current & Accrued Assets**	45,930,184	46,020,942	0%

BALANCE SHEET

Year: 2005

	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	1,567,729	1,506,087	4%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	183	Prelim. Survey & Investigation Charges	333,936		#DIV/0!
10	184	Clearing Accounts	312,330	205,998	52%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	1,599,301	1,530,609	4%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	3,064,215	2,879,082	6%
16	190	Accumulated Deferred Income Taxes	10,015,830	10,556,629	-5%
17		**TOTAL Deferred Debits**	16,893,341	16,678,405	1%
18					
19		**TOTAL Assets & Other Debits**	468,449,733	466,283,949	0%
		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	42,050,811	42,050,811	
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	109,306,716	127,312,068	-14%
35	217	(Less) Reacquired Capital Stock			
36	219	Accumulated Other Comprehensive Income	(1,435,853)	(1,597,727)	
37		**TOTAL Proprietary Capital**	170,836,188	188,679,666	-9%
38					
39	**Long Term Debt**				
40					
41	221	Bonds	137,275,000	135,320,000	1%
42	222	(Less) Reacquired Bonds			
43	223	Advances from Associated Companies			
44	224	Other Long Term Debt	21,930,648	21,895,035	0%
45	225	Unamortized Premium on Long Term Debt			
46	226	(Less) Unamort. Discount on L-Term Debt-Dr.			
47		**TOTAL Long Term Debt**	159,205,648	157,215,035	1%

Company Name: Black Hills Power, Inc.

BALANCE SHEET

Year: 2005

	Account Number & Title		Last 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	7,102,073	9,820,658	-28%
18	233	Notes Payable to Associated Companies	25,073,594	1,842,148	1261%
19	234	Accounts Payable to Associated Companies	331,517	1,623,712	-80%
20	235	Customer Deposits	560,421	568,937	-1%
21	236	Taxes Accrued	6,201,185	6,899,801	-10%
22	237	Interest Accrued	3,488,455	3,490,868	0%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	458,849	473,733	-3%
27	242	Miscellaneous Current & Accrued Liabilities	3,558,658	3,917,517	-9%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	46,774,752	28,637,374	63%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	2,237,737	3,305,036	-32%
34	253	Other Deferred Credits	13,282,677	14,072,034	-6%
35	255	Accumulated Deferred Investment Tax Credits	1,034,144	773,817	34%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	75,078,587	73,600,987	2%
39		**TOTAL Deferred Credits**	91,633,145	91,751,874	0%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		468,449,733	466,283,949	0%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2005

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Intangible Plant**			
3				
4	301 Organization			
5	302 Franchises & Consents			
6	303 Miscellaneous Intangible Plant			
7				
8	**TOTAL Intangible Plant**			
9				
10	**Production Plant**			
11				
12	Steam Production			
13				
14	310 Land & Land Rights			
15	311 Structures & Improvements			
16	312 Boiler Plant Equipment			
17	313 Engines & Engine Driven Generators			
18	314 Turbogenerator Units			
19	315 Accessory Electric Equipment			
20	316 Miscellaneous Power Plant Equipment			
21				
22	**TOTAL Steam Production Plant**			
23				
24	Nuclear Production			
25				
26	320 Land & Land Rights			
27	321 Structures & Improvements			
28	322 Reactor Plant Equipment			
29	323 Turbogenerator Units			
30	324 Accessory Electric Equipment			
31	325 Miscellaneous Power Plant Equipment			
32				
33	**TOTAL Nuclear Production Plant**			
34				
35	Hydraulic Production			
36				
37	330 Land & Land Rights			
38	331 Structures & Improvements			
39	332 Reservoirs, Dams & Waterways			
40	333 Water Wheels, Turbines & Generators			
41	334 Accessory Electric Equipment			
42	335 Miscellaneous Power Plant Equipment			
43	336 Roads, Railroads & Bridges			
44				
45	**TOTAL Hydraulic Production Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2005

	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			
21	352	Structures & Improvements			
22	353	Station Equipment			
23	354	Towers & Fixtures			
24	355	Poles & Fixtures			
25	356	Overhead Conductors & Devices			
26	357	Underground Conduit			
27	358	Underground Conductors & Devices			
28	359	Roads & Trails			
29					
30		**TOTAL Transmission Plant**			
31					
32		**Distribution Plant**			
33					
34	360	Land & Land Rights	26,304	26,304	
35	361	Structures & Improvements	5,970	5,970	
36	362	Station Equipment	441,924	441,924	
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	367,017	367,017	
39	365	Overhead Conductors & Devices	410,007	410,007	
40	366	Underground Conduit	909	909	
41	367	Underground Conductors & Devices	15,834	15,834	
42	368	Line Transformers	42,704	43,484	-2%
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**	1,320,314	1,321,094	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2005

	Account Number & Title		Last 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**		1,335,046	1,335,826	

MONTANA DEPRECIATION SUMMARY

Year: 2005

	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				
7	Distribution	1,301,841	360,344	356,846	2.78%
8	General	14,732	6,086	6,588	7.18%
9	**TOTAL**	1,316,573	366,430	363,434	9.96%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	N/A		
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		54.55%		
13	Preferred Stock				
14	Long Term Debt		45.45%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2005

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	19,208,760	18,005,352	7%
6	Depreciation	18,721,971	19,391,889	-3%
7	Amortization	363,032	473,032	-23%
8	Deferred Income Taxes - Net	5,388,321	(2,298,068)	334%
9	Investment Tax Credit Adjustments - Net	(279,115)	(260,327)	-7%
10	Change in Operating Receivables - Net	(1,489,003)	(3,201,547)	53%
11	Change in Materials, Supplies & Inventories - Net	(1,952,729)	(2,722,708)	28%
12	Change in Operating Payables & Accrued Liabilities - Net	(8,828,977)	5,094,068	-273%
13	Allowance for Funds Used During Construction (AFUDC)	(94,433)	(38,863)	-143%
14	Change in Other Assets & Liabilities - Net	1,847,561	4,923,115	-62%
15	Other Operating Activities (explained on attached page)			
16	**Net Cash Provided by/(Used in) Operating Activities**	32,885,388	39,365,943	-16%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(13,684,203)	(16,879,324)	19%
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	37,709,836		#DIV/0!
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(5,722,291)	2,942,223	-294%
27	**Net Cash Provided by/(Used in) Investing Activities**	18,303,342	(13,937,101)	231%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	18,650,000		#DIV/0!
32	Preferred Stock			
33	Common Stock			
34	Other:			
35	Net Increase in Short-Term Debt			
36	Other:	25,073,594	(23,231,446)	208%
37	Payment for Retirement of:			
38	Long-Term Debt	(71,486,080)	(1,990,613)	-3491%
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	(24,000,000)		#DIV/0!
45	Other Financing Activities (explained on attached page)			
46	**Net Cash Provided by (Used in) Financing Activities**	(51,762,486)	(25,222,059)	-105%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(573,756)	206,783	-377%
49	**Cash and Cash Equivalents at Beginning of Year**	1,051,579	477,823	120%
50	**Cash and Cash Equivalents at End of Year**	477,823	684,606	-30%

LONG TERM DEBT

Year: 2005

	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 Y	06/1988	06/2018	6,000,000	5,906,578	3,680,000	9.64%	366,128	9.95%
2									
3	Series Z	05/1991	05/2021	35,000,000	34,790,305	26,640,000	9.41%	2,562,690	9.62%
4									
5	Series AC	02/1995	02/2010	30,000,000	29,766,300	30,000,000	8.12%	2,418,000	8.06%
6									
7	Series AE	08/2002	08/2032	75,000,000	74,008,936	75,000,000	7.23%	5,455,881	7.27%
8									
9	2004 Pollution Control:								
10	Campbell Cty 4.8%	11/2004	10/2014	1,550,000	1,517,018	1,550,000	4.80%	78,422	5.06%
11	Campbell Cty 5.35%	11/2004	10/2014	12,200,000	11,964,016	12,200,000	5.35%	664,327	5.45%
12	Pennington Cty 4.8%	11/2004	10/2014	2,050,000	1,999,347	2,050,000	4.80%	110,752	5.40%
13	Weston Cty 4.8%	11/2004	10/2014	2,850,000	2,791,873	2,850,000	4.80%	141,680	4.97%
14									
15	1994 A Environ Improv Bomd	06/1994	06/2024	3,000,000	2,930,057	2,855,000	4.35%	86,325	3.02%
16									
17	Bear Paw Energy	06/2000	05/2012	1,078,000	1,078,000	390,035	13.70%	56,276	14.43%
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			168,728,000	166,752,430	157,215,035		11,940,481	7.59%

PREFERRED STOCK

Year: 2005

	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										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2005

		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: 2005

	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				
30	Note: This schedule is not completed because			
31	Montana revenues represent less than 1%			
32	of the Company's revenues.			
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: 2005

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,317
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	(363)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	954
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	859
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	859
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	859
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	20
37		Industrial	2
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	35
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	75,518
45		Average Annual Residential Cost per (Kwh) (Cents) *	7.66
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	39
48		Gross Plant per Customer	38,166

MONTANA CUSTOMER INFORMATION

Year: 2005

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**					

MONTANA EMPLOYEE COUNTS

Year: 2005

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

Company Name: Black Hills Power, Inc. **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2006

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2005

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	13	1800	339	274,982	89,449
2	Feb.	7	1900	316	230,325	65,240
3	Mar.	14	1000	290	250,877	76,625
4	Apr.	21	1100	279	250,916	89,873
5	May	11	2100	287	260,907	93,855
6	Jun.	22	1400	375	247,572	71,017
7	Jul.	13	1700	401	253,721	49,960
8	Aug.	8	1500	394	285,667	90,289
9	Sep.	8	1600	340	298,836	130,744
10	Oct.	4	1900	290	256,678	87,673
11	Nov.	28	1800	334	267,459	96,287
12	Dec.	6	1900	356	287,332	86,958
13	**TOTAL**				3,165,272	1,027,970

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	1,728,823	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,582,843
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	37,239	for Resale	460,558
7	(Less) Energy for Pumping			
8	**NET Generation**	1,766,062	Non-Requirements Sales	
9	Purchases	1,409,393	for Resale	1,027,970
10	Power Exchanges			
11	Received	17,384	Energy Furnished	
12	Delivered	(36,644)	Without Charge	
13	**NET Exchanges**	(19,260)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	2,417,922	Electric Utility	8,531
16	Delivered	(2,408,845)		
17	**NET Transmission Wheeling**	9,077	Total Energy Losses	85,370
18	Transmission by Others Losses			
19	**TOTAL**	3,165,272	**TOTAL**	3,165,272

SOURCES OF ELECTRIC SUPPLY

Year: 2005

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	1,409
2					
3	Thermal	Ben French	Rapid City, SD	10	912
4					
5	Thermal	Ben French	Rapid City, SD	24	152,533
6					
7	Thermal	Osage	Osage, WY	35	245,089
8					
9	Thermal	Wyodak	Gillette, WY	69	533,953
10					
11	Thermal	Neil Simpson Complex	Gillette, WY	112	797,246
12					
13	Thermal	Neil Simpson Complex	Gillette, WY	39	17,105
14					
15	Thermal	Lange	Rapid City, SD	39	17,815
16					
17	Purchases	See Schedule 32			1,409,393
18					
19	Wheeling	See Schedule 32			9,077
20					
21	Total Interchange	See Schedule 32			(19,260)
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			426	3,165,272

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

SCHEDULE 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2005

	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							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**						

Company Name:

Schedule 35a

Electric Universal System Benefits Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2						
3						
4						
5						
6						
7						
8	Market Transformation					
9						
10						
11						
12						
13						
14						
15	Renewable Resources					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Large Customer Self Directed					
36						
37						
38						
39						
40						
41						
42	Total					
43	Number of customers that received low income rate discounts					
44	Average monthly bill discount amount ($/mo)					
45	Average LIEAP-eligible household income					
46	Number of customers that received weatherization assistance					
47	Expected average annual bill savings from weatherization					
48	Number of residential audits performed					

Company Name:

Schedule 35b

Montana Conservation & Demand Side Management Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2						
3						
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Other					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46	Total					

MONTANA CONSUMPTION AND REVENUES

Year: 2005

	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	$6,091	$5,484	78	73	13	13
2	Commercial - Small	$16,193	$13,972	174	145	20	19
3	Commercial - Large	$836,795	$758,705	17,482	16,470	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**	$859,079	$778,161	17,734	16,688	35	34