YEAR ENDING DECEMBER 2008

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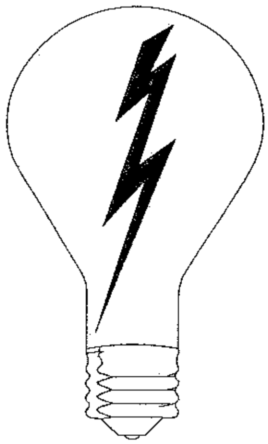
PUBLIC SERVICE
COMMISSION

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

REVISED - 2005

Electric Annual Report

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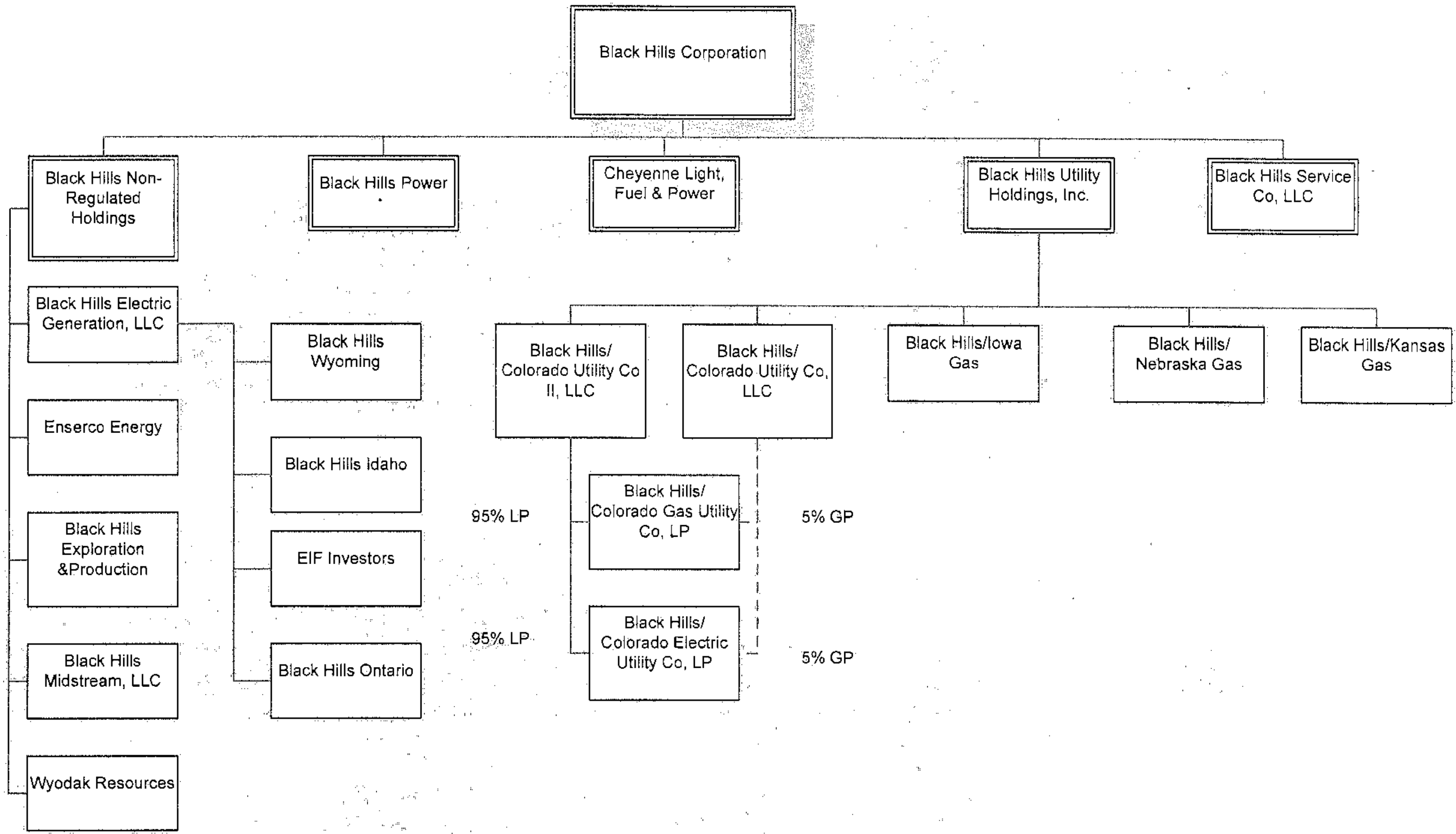
Description	Schedule

Black Hills Organizational Chart (Legal Structure)



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

IDENTIFICATION

Year: **2008**

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:	625 Ninth Street- 5th Floor Rapid City, SD 57701
5.	Person Responsible for This Report:	Chris Kilpatrick Director of Rates- Electric Regulation
5a.	Telephone Number:	605-721-2748

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 625 Ninth Street, Rapid City, SD 57701
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	84,750
3	John R. Howard	Rapid City, SD	83,500
4	Kay S. Jorgensen	Spearfish, SD	86,000
5	David C. Ebertz	Gillette, WY	71,000
6	Gary L Pechota	Bethlehem, PA	64,750
7	Stephen D. Newlin	Avon Lake, OH	67,250
8	Jack W. Eugster	Rapid City, SD	69,750
9	Warren L Robinson	Rapid City, SD	66,750
10	John B. Vering	Southlake, TX	72,250
11			
12	(a) Mr. Emery is an officer of the company and is not compensated for his services		
13	as a director.		
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Officers

Year: 2008

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman & Chief Executive Officer		David R. Emery
2	President & Chief Operating Officer- Utilities		Linden R. Evans
3	Executive Vice President and CFO		Anthony S. Cleberg
4	Senior Vice President - Corporate Administration		James M. Mattern
5	Senior Vice President - Governance & Corporate Secretary		Roxann R. Basham
6	Vice President - Corporate Controller		Perry S. Krush
7	Vice President - Finance		Jeffrey B. Berzina
8	Vice President, Treasurer & Chief Risk Officer		Garner M. Anderson
9	Vice President - Regulatory and Governmental Affairs		Kyle D. White
10	Vice President - Strategic Planning & Development		Richard W. Kinzley
11	Vice President - Electric Utilities		Stuart A. Wevik
12	Vice President - Power Delivery		Mark L. Lux
13	Vice President and General Manager - Gillette Complex		Gregory L. Hager
14	Vice President - Customer Service		Randy D. Winkelman
15	Vice President - Operations		Richard C. Loomis
16	Vice President - Electric Regulatory Services		Brian G. Iverson
17	Senior Vice President - General Counsel and Corporate Compliance O		Steven J. Helmers
18	Senior Vice President - Chief Information Officer		Scott A. Buchholz
19	Senior Vice President - Communication and Investor Relations		Lynnette K. Wilson
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CORPORATE STRUCTURE

Year: 2008

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	29,181,456	100.00%
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42				100.00%
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50	**TOTAL**		29,181,456	

Company Name: Black Hills Power, Inc.

CORPORATE ALLOCATIONS

Year: 2008

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Not significant to Montana Operations.					
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34	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2008

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 Development Corp.	Coal Sales to Utility	Fair Market Value (based on similar arms-length transactions)	15,469,397	27.18%	283,090
2	Enserco Energy, Inc	Gas Sales to Utility	Fair Market Value (based on similar arms-length transactions)	8,049,310	0.13%	111,080
3	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	6,387,234	4.61%	116,886
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32	TOTAL			29,905,941		511,056

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2008

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 Development Corp.	Electricity	Wyoming Industrial Rate	985,915	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point Open Access Transmission Tariff	478,180	100.00%	
3	Black Hills Wyoming	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	509,721	100.00%	
4	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	2,778,037	3.30%	50,838
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32	**TOTAL**			4,751,853		50,838

MONTANA UTILITY INCOME STATEMENT

Year: 2008

		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	199,440,689	228,236,534	14.44%
2					
3		Operating Expenses			
4	401	Operation Expenses	115,701,592	153,203,703	32.41%
5	402	Maintenance Expense	8,991,643	13,048,642	45.12%
6	403	Depreciation Expense	20,611,646	20,778,345	0.81%
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 Credits (SD-ECA)		(4,175,466)	#DIV/0!
11	408.1	Taxes Other Than Income Taxes	6,248,208	6,543,569	4.73%
12	409.1	Income Taxes - Federal	8,685,058	(6,567,055)	-175.61%
13		- Other	18,703		-100.00%
14	410.1	Provision for Deferred Income Taxes	5,182,994	17,483,646	237.33%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(1,085,400)	(1,342,539)	-23.69%
16	411.4	Investment Tax Credit Adjustments	(233,329)	(69,171)	70.35%
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**	164,272,519	199,055,078	21.17%
21		**NET UTILITY OPERATING INCOME**	35,168,170	29,181,456	-17.02%

MONTANA REVENUES

SCHEDULE 9

		Account Number & Title	Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	7,013	7,622	8.67%
3	442	Commercial & Industrial - Small	70,462	64,443	-8.54%
4		Commercial & Industrial - Large	1,474,385	2,004,360	35.95%
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**	1,551,861	2,076,425	33.80%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	1,551,861	2,076,425	33.80%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	1,551,861	2,076,425	33.80%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	(69)	(0)	99.34%
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**	(69)	(0)	99.34%
26		**Total Electric Operating Revenues**	1,551,792	2,076,425	33.81%

(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 BHC or the Parent, a public registrant listed on the New York Stock Exchange.

Basis of Presentation

The financial statements include the accounts of Black Hills Power, Inc. and also the Company's ownership interests in the assets, liabilities and expenses of its jointly owned facilities (Note 3).

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). Additionally, these requirements differ from GAAP related to the presentation of certain items including deferred income taxes, and cost of removal liabilities. The Company's notes to the financial statements are prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of the Company's FERC basis financial statements contained herein.

Use of Estimates

The preparation of financial statements in conformity with GAAP 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, unbilled revenues, long-lived asset values and useful lives, asset retirement obligations, employee benefits plans and contingency accruals. Actual results could differ from those estimates.

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 FERC.

The Company's regulated utility operations follow the provisions of 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 could be an extraordinary non-cash charge to operations in an amount that could be material.

On December 31, 2008 and 2007, the Company had the following regulatory assets and liabilities:

	2008	2007
Regulatory assets:		
Unamortized loss on reacquired debt	$ 2,367	$ 2,527
AFUDC	4,995	4,139
Defined benefit postretirement plans	26,256	2,998
Deferred energy costs	4,382	939
Other	199	235
	$ 38,199	$ 10,838
Regulatory liabilities:		
Deferred income taxes	$ 1,857	$ 2,094
Cost of removal for utility plant	11,705	8,510
Other	79	760
	$ 13,641	$ 11,364

Regulatory assets are primarily recorded for the probable future revenue to recover the costs associated with defined benefit postretirement plans, future income taxes related to the deferred tax liability for the equity component of AFUDC of utility assets and unamortized losses on reacquired debt. To the extent that energy costs are under-recovered or over-recovered during the year, they are recorded as a regulatory asset or liability, respectively. Regulatory liabilities include the probable future decrease in rate revenues related to a decrease in deferred tax liabilities for prior reductions in statutory federal income tax rates, gains associated with regulated utilities' defined benefit postretirement plans and the cost of removal for utility plant, recovered through the Company's electric utility rates. Regulatory assets are included in Other current assets and Other assets, Regulatory assets on the accompanying Balance Sheet. Regulatory liabilities are included in Accrued liabilities and Deferred credits and other liabilities, Regulatory liabilities on the accompanying Balance Sheet.

Allowance for Funds Used During Construction

AFUDC represents the approximate composite cost of borrowed funds and a return on capital used to finance a project. AFUDC for the years ended December 31, 2008, 2007 and 2006 was $6.2 million, $0.9 million, and $0.6 million, respectively. The equity component of AFUDC for 2008, 2007 and 2006 was $3.6 million, $0.6 million and $0.4, respectively. The borrowed funds component of AFUDC for 2008, 2007 and 2006 was $2.6 million, $0.3 million and $0.2 million, respectively. The equity component of AFUDC is included in Other income (expense), and the borrowed funds component of AFUDC is netted in Interest expense on the accompanying Statements of Income.

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 on a weighted-average cost 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, 2008 and 2007, there were no market adjustments related to fuel.

Deferred Financing Costs

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

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost when placed in service. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Removal costs associated with non-legal obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. Ordinary repairs and maintenance of property are charged to operations as incurred.

Depreciation provisions for regulated electric property, plant and equipment is computed on a straight-line basis using an annual composite rate of 3.2% in 2008, 3.1% in 2007 and 3.0% in 2006.

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 fix the interest on its variable rate debt. Contracts that qualify as derivatives under SFAS 133, and that are not exempted such as normal purchase/normal sale, are required to 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, net of tax, 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 2008, 2007 or 2006.

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, as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. The Company classifies deferred tax assets and liabilities into current and non-current amounts based on the classification of the related assets and liabilities.

The Company files a federal income tax return with other affiliates. For financial statement purposes, federal income taxes are allocated to the individual companies based on amounts calculated on a separate return basis.

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.

Recently Adopted Accounting Pronouncements

SFAS 157

During September 2006, the FASB issued SFAS 157. This Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 does not expand the application of fair value accounting to any new circumstances, but applies the framework to other accounting pronouncements that require or permit fair value measurement. The Company applies fair value measurements to certain assets and liabilities, primarily commodity derivatives.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. As of January 1, 2008, the Company adopted the provisions of SFAS 157 for all assets and liabilities measured at fair value except for non-financial assets and liabilities measured at fair value on a non-recurring basis, as permitted by FSP FAS 157-2. SFAS 157 also requires new disclosures regarding the level of pricing observability associated with instruments carried at fair value. On October 10, 2008, the FASB issued FSP FAS 157-3. It was effective upon issuance including prior periods for which financial statements have not been issued. This FSP clarifies the application of SFAS 157 in a market that is not active. The adoption of SFAS 157 and related FSPs did not have a material impact on the Company's financial position, results of operations or cash flows.

SFAS 158

During September 2006, the FASB issued SFAS 158. This Statement requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position, and provides for related disclosures. The Company applied the recognition provisions of SFAS 158 as of December 31, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 requires the measurement of the funded status of the plan to coincide with the date of the year-end statement of financial position. In accordance with SFAS 158, the measurement date for the funded status of the Company's pension and other postretirement benefit plans was changed to December 31 from September 30 (see Note 9).

SFAS 159

SFAS 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS 159 was adopted on January 1, 2008 and did not have an impact on the Company's financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

SFAS 141(R)

In December 2007, the FASB issued SFAS 141(R). SFAS 141(R) requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date to be measured at their fair values as of the acquisition date, with limited exceptions specified in the statement. This replaces the cost allocation process in SFAS 141, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. Costs to issue debt or equity securities shall be accounted for under other applicable GAAP. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after December 15, 2008. We expect SFAS 141(R) will not have an impact on our financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of any acquisitions we consummate after the effective date. If previously recorded income tax liabilities acquired in a business combination reverse subsequent to the adoption of SFAS 141(R), such reversals will affect expense including income tax expense in the period of reversal. Management is assessing the full impact SFAS 141(R) might have on future financial statements.

SFAS 160

In December 2007, the FASB issued SFAS 160. SFAS 160 amends ARB 51 and requires:

- Ownership interests in subsidiaries held by other parties other than the parent be clearly identified on the consolidated statement of financial position within equity, but separate from the parent's equity;

- Consolidated net income attributable to the parent and to the non-controlling interest be clearly identified on the face of the consolidated statement of income;

- Changes in a parent's ownership interest while the parent retains controlling financial interest be accounted for consistently as equity transactions;

- When a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value; and

- Sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners.

SFAS 160 is effective for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Management does not expect the adoption of SFAS 160 to have a significant effect on the Company's financial statements.

SFAS 161

In March 2008, the FASB issued SFAS 161, which requires enhanced disclosures about how derivative and hedging activities affect an entity's financial position, financial performance and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Management does not expect the adoption of SFAS 161 to have a significant effect on the Company's financial statements.

FSP FAS 132(R)-1

During December 2008 the FASB issued FSP FAS 132(R)-1, "Employers Disclosures about Postretirement Benefit Plan Assets." The objectives of the disclosures about plan assets in an employers defined benefit pension or other postretirement plan are to provide users of financial statements with an understanding of:

- How investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies;
- The major categories of plan assets;
- The input and valuation techniques used to measure the fair value of plan assets;
- The effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and
- Significant concentrations of risk within plan assets.

FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009. Management does not expect the adoption of FSP FAS 132(R)-1 to have a significant effect on the Company's financial statements.

(2) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31, consisted of the following (in thousands):

	2008	2008 Weighted Average Useful Life	2007	2007 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 326,606	47	$ 322,572	47	30-62
Transmission	70,470	45	70,897	45	35-55
Distribution	249,652	37	238,799	37	15-65
Plant acquisition adjustment	4,870	32	4,870	32	32
General	47,127	23	39,296	22	10-50
Total electric plant	698,725		676,434		
Less accumulated depreciation and amortization	281,220		266,583		
Electric plant net of accumulated depreciation and amortization	417,505		409,851		
Construction work in progress	144,966		19,018		
Net electric plant	$ 562,471		$ 428,869		

(3) 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% interest and PacifiCorp owns an 80% interest in the Wyodak Plant (Plant), a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. The Company receives 20% of the Plant's capacity and is committed to pay 20% of its additions, replacements and operating and maintenance expenses. As of December 31, 2008 and 2007, the Company's investment in the Plant included \$79.1 million and \$80.4 million, respectively, in electric plant and \$50.8 million and \$43.5 million, respectively, 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 \$8.0 million, \$7.3 million and \$7.9 million for the years ended December 31, 2008, 2007 and 2006, respectively, and is included in the corresponding categories of operating expenses in the accompanying Statements of Income.

- The Company also owns a 35% interest and Basin Electric owns a 65% interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides the Company with access to both the WECC region and the MAPP region. The total transfer capacity of the transmission tie is 400 MW – 200 MW West to East and 200 MW from East to West. The Company is committed to pay 35% of the additions, replacements and operating and maintenance expenses. The Company's share of direct expenses was \$0.1 million for each of the years ended December 31, 2008, 2007 and 2006. As of December 31, 2008 and 2007, the Company's investment in the transmission tie was \$19.8 million, with \$2.5 million and \$2.0 million, respectively, of accumulated depreciation and is included in the corresponding captions in the accompanying Balance Sheets.

(4) RISK MANAGEMENT

The Company holds natural gas in storage for use as fuel for generating electricity with its gas-fired combustion turbines. To minimize associated price risk and seasonal storage level requirements, the Company utilizes various derivative instruments in managing these risks. As of December 31, 2008, there were no derivative contracts outstanding. The balance on December 31, 2007, the Company had the following derivatives and related balances (in thousands):

	Notional*	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income
December 31, 2007							
Natural gas swaps	610,000	0.33	\$ 238	\$ —	\$ 68	\$ —	\$ 170

*gas in MMbtus

(5) LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	2008	2007
	(in thousands)	
First mortgage bonds:		
8.06% due 2010	$ 30,000	$ 30,000
9.49% due 2018	2,810	3,100
9.35% due 2021	21,645	23,310
7.23% due 2032	75,000	75,000
	129,455	131,410
Other long-term debt:		
Pollution control revenue bonds at 4.8% due 2014	6,450	6,450
Pollution control revenue bonds at 5.35% due 2024	12,200	12,200
Other	3,104	3,158
	21,754	21,808
Total long-term debt	151,209	153,218
Less current maturities	(2,016)	(2,009)
Net long-term debt	$ 149,193	$ 151,209

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 in 2009; $32.0 million in 2010; $2.0 million a year for the years 2011, 2012 and 2013; and $111.2 million thereafter.

(6) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 4	$ 4	$ 2,033	$ 2,033
Derivative financial instruments – assets	$ —	$ —	$ 238	$ 238
Derivative financial instruments – liabilities	$ —	$ —	$ 68	$ 68
Long-term debt	$ 151,209	$ 144,107	$ 153,218	$ 168,042

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

Cash and Cash Equivalents

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

Derivative Financial Instruments

These instruments are carried at fair value. Descriptions of the instruments the Company uses are included in Note 4.

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.

(7) INCOME TAXES

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

	2008	2007	2006
Current	$ (6,521)	$ 8,704	$ 12,928
Deferred	16,072	3,864	(2,799)
	$ 9,551	$ 12,568	$ 10,129

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

Years ended December 31,	2008	2007
Deferred tax assets, current:		
Asset valuation reserve	$ 129	$ 136
Employee benefits	932	399
	1,061	535
Deferred tax liabilities, current:		
Prepaid expenses	213	181
Items of other comprehensive income	—	290
Deferred credits	1,580	—
Other	—	82
	1,793	553
Net deferred tax liability, current	$ 732	$ 18
Deferred tax assets, non-current:		
Plant related differences	$ 1,151	$ 1,316
Regulatory liabilities	10,156	4,533
Employee benefits	3,528	3,366
Items of other comprehensive income	227	226
Other	128	128
	15,190	9,569
Deferred tax liabilities, non-current:		
Accelerated depreciation and other plant related differences	83,112	68,250
AFUDC	3,247	2,690
Regulatory assets	11,270	5,222
Employee benefits	2,237	2,284
Other	828	884
	100,694	79,330
Net deferred tax liability, non-current	$ 85,504	$ 69,761
Net deferred tax liability	$ 86,236	$ 69,779

The following table reconciles the change in the net deferred income tax liability from December 31, 2007, to December 31, 2008, to the deferred income tax expense (in thousands):

		2008
Increase in deferred income tax liability from the preceding table	$	16,457
Deferred taxes related to regulatory assets and liabilities		(1,200)
Deferred taxes associated with other comprehensive loss		38
Deferred taxes related to property tax differences		767
Other		10
Deferred income tax expense for the period	$	16,072

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

	2008	2007	2006
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.7)	(1.0)	(1.3)
Equity AFUDC	(3.6)	—	—
IRS tax exam adjustment*	—	—	2.6
Other	(1.1)	(0.5)	(1.2)
	29.6%	33.5%	35.1%

*As a result of a settlement of an Internal Revenue Service (IRS) exam.

FIN 48

The Company adopted the provisions of FIN 48 on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken. The impact of the implementation of FIN 48 had no effect on the financial statements of the Company.

The following table reconciles the total amounts of unrecognized tax benefits at the beginning and end of the period (in thousands):

Unrecognized tax benefits at December 31, 2007	$	—
Additions for current year tax positions		767
Unrecognized tax benefits at December 31, 2008	$	767

None of the total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate.

It is the Company's continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the year ended December 31, 2008, the interest expense recognized was not material to the financial results of the Company.

The Company files income tax returns in the United States federal jurisdiction. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statutes of limitations prior to December 31, 2009.

(8) COMPREHENSIVE INCOME

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

2008	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Pension liability adjustment	$ (4)	$ 1	$ (3)
Reclassification adjustments of cash flow hedges settled and included in net income	(107)	38	(69)
Comprehensive loss	$ (111)	$ 39	$ (72)

2007	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Pension liability adjustment	$ 115	$ (39)	$ 76
Reclassification adjustments of cash flow hedges settled and included in net income	424	(148)	276
Net change in fair value of derivatives designated as cash flow hedges	(1,069)	372	(697)
Comprehensive loss	$ (530)	$ 185	$ (345)

2006	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Pension liability adjustment	$ 48	$ (17)	$ 31
Amortization of cash flow hedges settled and deferred in AOCI and reclassified into interest expense	64	(22)	42
Net change in fair value of derivatives designated as cash flow hedges	1,097	(384)	713
Comprehensive income	$ 1,209	$ (423)	$ 786

Balances by classification included within Accumulated other comprehensive loss on the accompanying Balance Sheets are as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
As of December 31, 2008	$ (932)	$ (417)	$ (1,349)
As of December 31, 2007	$ (861)	$ (416)	$ (1,277)

(9) EMPLOYEE BENEFIT PLANS

SFAS 158

The application of SFAS 158 requires recognition of the funded status of postretirement benefit plans in the statement of financial position. The funded status for pension plans is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation.

Prior to the December 31, 2006 effective date of SFAS 158, liabilities recorded for postretirement benefit plans were reduced by any unrecognized net periodic benefit cost. Upon adoption of SFAS 158, the unrecognized net periodic benefit cost, previously recorded as an offset to the liability for benefit obligations, was reclassified within AOCI, net of tax. The Company applied the guidance under SFAS 71, and accordingly, the unrecognized net periodic benefit cost that would have been reclassified to AOCI was alternatively recorded as a regulatory asset or regulatory liability, net of tax.

SFAS 158 required that the measurement date of plans be the date of the Company's year-end balance sheet. The Company had used a September 30 measurement date. During 2008, the Company changed the measurement date to December 31. Therefore, $0.2 million, net of tax, was recognized as an adjustment to retained earnings. The amortization of prior service costs for October 1, 2007 to December 31, 2007 was less than $0.1 million, net of tax, and the service cost, interest cost and expected return on plan assets for October 1, 2007 to December 31, 2007 was $0.2 million, net of tax.

Defined Benefit Pension Plan

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company who meet certain eligibility requirements. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Company's funding policy is in accordance with the federal government's funding requirements. The Plan's assets are held in trust and consist primarily of equity and fixed income investments. The Company uses a December 31 measurement date for the Plan.

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% for the 2008 and 2007 plan years. For determining the expected long-term rate of return for equity assets, the Company reviewed interest rate trends and annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2008, 8.4%, 11.0%, 9.0% and 9.2%, respectively. Fund management fees were estimated to be 0.18% for S&P 500 Index assets and 0.45% for other assets. The expected long-term rate of return on fixed income investments was 6.0%; the return was based upon historical returns on 10-year treasury bonds of 7.1% from 1962 to 2007, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 4.0%; expected cash returns were estimated to be 2.0% below long-term returns on intermediate-term bonds.

Plan Assets

Percentage of fair value of Plan assets at December 31:

	2008	2007
Equity	68%	76%
Fixed income	28	21
Cash	4	3
Total	100%	100%

As a result of the severe decline in equity values in the fourth quarter of 2008 and in light of the improved relative value of fixed income investment opportunities, we are undergoing a review to consider a revision of the pension plan investment allocations.

The revision is expected to result in a higher fixed income allocation. Until the investment allocation review is complete and implemented, we have suspended our practice of rebalancing the portfolio on a quarterly basis. This has resulted in an investment allocation of 68% equities and 32% fixed income/cash at December 31, 2008.

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 and fixed income assets. The policy provides that the Plan will maintain a passive core United States Stock portfolio based on a broad market index. Complementing this core will be investments in United States 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 made no contributions to the Plan in 2008, but expects to contribute $0.3 million to the Plan in 2009.

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 December 31 measurement date for the Plans.

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 2009. Contributions are expected to be made in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in the Company's Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service to the Company are entitled to postretirement healthcare benefits. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. The Company may amend or change the Plan periodically. The Company is not pre-funding its retiree medical plan. The Company uses a December 31 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 of the Medicare Part D subsidy on the accumulated postretirement benefit obligation for the fiscal year ending December 31, 2008, was an actuarial gain of approximately $1.0 million. The effect on 2009 net periodic postretirement benefit cost will be a decrease of approximately $0.1 million.

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 2009. Contributions are expected to be made in the form of benefit payments.

The following tables provide a reconciliation of the Employee Benefit Plan's obligations and fair value of assets for 2008 and 2007, components of the net periodic expense for the years ended 2008, 2007 and 2006 and elements of regulatory assets and liabilities and AOCI for 2008 and 2007.

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 48,937	$ 50,340	$ 1,958	$ 1,999	$ 6,649	$ 6,791
Service cost	1,396	1,137	—	—	264	211
Interest cost	3,790	2,923	150	116	522	398
Actuarial (gain) loss	2,712	(328)	65	(54)	506	(571)
Amendments	—	—	—	—	—	—
Discount rate change	—	(2,641)	—	—	—	—
Benefits paid	(2,838)	(2,145)	(142)	(103)	(830)	(638)
Asset transfer to affiliate	(2,032)	(349)	(359)	—	(297)	(19)
Medicare Part D adjustment	—	—	—	—	71	75
Plan participant's contributions	—	—	—	—	508	402
Net increase (decrease)	3,028	(1,403)	(286)	(41)	744	(142)
Projected benefit obligation at end of year	$ 51,965	$ 48,937	$ 1,672	$ 1,958	$ 7,393	$ 6,649

A reconciliation of the fair value of Plan assets (as of the December 31 measurement date) is as follows:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Beginning market value of plan assets	$ 52,466	$ 46,916	$ —	$ —	$ —	$ —
Investment income	(8,771)	8,044	—	—	—	—
Benefits paid	(2,249)	(2,145)	—	—	—	—
Asset transfer to affiliate	—	(349)	—	—	—	—
Ending market value of plan assets	$ 41,446	$ 52,466	$ —	$ —	$ —	$ —

Amounts recognized in the statement of financial position consist of:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Regulatory asset (liability)	$ 26,256	$ 2,998	$ —	$ —	$ (11)	$ (480)
Current liability	—	—	109	129	223	186
Non-current asset (liability)	(19,864)	3,529	(1,564)	(1,801)	(7,169)	(6,399)

Company Name: Black Hills Power, Inc.

Schedule 8A
Notes to the Financial Statements for Black Hills Corporation

Accumulated Benefit Obligation

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans (in thousands)		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
Accumulated benefit obligation	$ 43,894	$ 41,823	$ 1,622	$ 1,808	$ 7,393	$ 6,649

Components of Net Periodic Expense

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans (in thousands)			Non-pension Defined Bene[illegible] Postretirement Plans		
	2008	2007	2006	2008	2007	2006	2008	2007	2[illegible]
Service cost	$ 1,117	$ 1,137	$ 1,085	$ —	$ —	$ —	$ 211	$ 211	$ [illegible]
Interest cost	3,032	2,923	2,720	120	116	113	417	398	[illegible]
Expected return on assets	(4,374)	(3,885)	(3,557)	—	—	—	—	—	
Amortization of prior service cost	112	103	103	1	1	1	—	—	
Amortization of transition obligation	—	—	—	—	—	—	51	51	
Recognized net actuarial loss	—	408	665	44	57	67	(1)	—	
Net periodic expense	$ (113)	$ 686	$ 1,016	$ 165	$ 174	$ 181	$ 678	$ 660	$ [illegible]

AOCI

In accordance with SFAS 158, amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31, are as follows:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans (in thousands)		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
Net loss	$ —	$ —	$ (347)	$ (418)	$ —	$ —
Prior service cost	—	—	(1)	(1)	—	—
Transition obligation	—	—	—	—	—	—
	$ —	$ —	$ (348)	$ (419)	$ —	$ —

The amounts in AOCI, regulatory assets or regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2009 are as follows:

	Defined Benefits Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans (in thousands)	Non-pension Defined Benefit Postretirement Plans
Net loss	$ 1,118	$ 28	$ —
Prior service cost	73	—	—
Transition obligation	—	—	33
Total net periodic benefit cost expected to be recognized during calendar year 2008	$ 1,191	$ 28	$ 33

Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
Weighted-average assumptions used to determine benefit obligations:	2008	2007	2006	2008	2007	2006	2008	2007	2006
Discount rate	6.20%	6.35%	5.95%	6.20%	6.35%	5.95%	6.10%	6.35%	5.95%
Rate of increase in compensation levels	4.25%	4.34%	4.31%	5.00%	5.00%	5.00%	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2008	2007	2006	2008	2007	2006	2008	2007	2006
Discount rate	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%
Expected long-term rate of return on assets*	8.50%	8.50%	8.50%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	4.34%	4.31%	4.34%	N/A	5.00%	5.00%	N/A	N/A	N/A

* The expected rate of return on plan assets remained at 8.50% for the calculation of the 2009 net periodic pension cost.

The healthcare cost trend rate assumption for 2008 fiscal year benefit obligation determination and 2009 fiscal year expense is a 9% increase for 2009 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013. The healthcare cost trend rate assumption for the 2008 fiscal year benefit obligation determination and 2008 fiscal year expense was a 10% increase for 2008 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1% increase in the healthcare cost trend assumption would increase the service and interest cost $0.1 million or 21% and the accumulated periodic postretirement benefit obligation $1.3 million or 18%. A 1% decrease would reduce the service and interest cost by $0.1 million or 16% and the accumulated periodic postretirement benefit obligation $1.0 million or 14%.

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

			Non-pension Defined Benefit Postretirement Plans		
	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Expected Gross Benefit Payments	Expected Medicare Part D Drug Benefit Subsidy	Expected Net Benefit Payments
2009	$ 2,440	$ 109	$ 298	$ (75)	$ 223
2010	2,561	107	340	(83)	257
2011	2,695	111	384	(91)	293
2012	2,780	92	404	(100)	304
2013	2,917	74	441	(108)	333
2014-2018	16,817	421	2,667	(643)	2,024

Defined Contribution Plan

The Parent sponsors a 401(k) savings plan in which employees of the Company may participate. Participants may elect to invest up to 20% of their eligible compensation on a pre-tax basis, up to a maximum amount established by the Internal Revenue Service. The Company provides a matching contribution of 100% of the employee's annual contribution up to a maximum of 3% of eligible compensation. Matching contributions vest at 20% per year and are fully vested when the participant has 5 years of service with the Company. The Company's matching contributions were $0.7 for 2008, $0.6 million for 2007 and $0.6 million for 2006.

(10) RELATED-PARTY TRANSACTIONS

Receivables and Payables

The Company has accounts receivable balances related to transactions with other BHC subsidiaries. The balances were $12.6 million and $8.9 million as of December 31, 2008 and 2007, respectively. The Company also has accounts payable balances related to transactions with other BHC subsidiaries. The balances were $10.4 million and $3.2 million as of December 31, 2008 and 2007, respectively.

Money Pool Notes Receivable and Notes Payable

The Company has a Utility Money Pool Agreement with the Parent, Cheyenne Light and Black Hills Utility Holdings. 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.

The Company through the Utility Money Pool had a net note payable balance to the Parent of $70.2 million as of December 31, 2008 and a note receivable balance from Cheyenne Light and the Parent of $10.3 million as of December 31, 2007. Advances under this note bear interest at 0.70% above the daily LIBOR rate (1.14% at December 31, 2008). Net interest expense of $0.9 million and net interest income of $0.9 million was recorded for the years ended December 31, 2008 and 2007, respectively.

Other Balances and Transactions

The Company also received revenues of approximately $1.2 million, $1.9 million and $2.4 million for the years ended December 31, 2008, 2007 and 2006, respectively, from Black Hills Wyoming, Inc. for the transmission of electricity.

The Company recorded revenues of $0.2 million, $1.4 million and $3.3 million for the years ending December 31, 2008, 2007 and 2006, respectively, relating to payments received pursuant to a natural gas swap entered into with Enserco.

The Company received revenues of approximately $2.8 million for the year ended December 31, 2008, from Cheyenne Light for the sale of electricity and dispatch services.

The Company purchases coal from WRDC. The amount purchased during the years ended December 31, 2008, 2007 and 2006 was $15.5 million, $12.6 million and $10.8 million, respectively. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.

The Company purchases excess power generated by Cheyenne Light. The amount purchased during the year ended December 31, 2008 was $6.4 million.

In order to fuel its combustion turbine, the Company purchased natural gas from Enserco. The amount purchased during the years ended December 31, 2008, 2007 and 2006 was approximately $8.0 million, $4.5 million and $7.2 million, respectively. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.

In addition, the Company also pays the Parent for allocated corporate support service cost incurred on its behalf. Corporate costs allocated from the Parent were $12.4 million and $11.3 million for the years ended December 31, 2008 and 2007, respectively.

The Company has funds on deposit from Black Hills Wyoming for transmission system reserve in the amount of $1.9 million and $1.8 million at December 31, 2008 and 2007, respectively, which is included in Deferred credits and other liabilities, Other on the accompanying Balance Sheets. Interest on the deposit accrues quarterly at an average prime rate (5% at December 31, 2008).

On January 1, 2006, the Company assumed the assets and liabilities of Mayer Radio, Inc., a subsidiary of the Parent. Results from the assumption of the business unit activity were not material to the Company.

On August 28, 2008 the Company entered into a contract with Cheyenne Light under which Cheyenne Light will sell up to 20 MW wind-generated, renewable energy to the Company until 2028. Purchases from this agreement during 2008 were $0.6 million.

(11) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 MW of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 MW (5 MW 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 $11.6 million in 2008, $10.9 million in 2007 and $10.1 million in 2006.

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 the Company's capacity and energy will be transmitted by PacifiCorp: 17 MW in 2005-2006 and 50 MW in 2007-2023. Costs incurred under this agreement were $1.2 million in 2008, $1.2 million in 2007 and $0.4 million in 2006.

- A 20-year power purchase agreement with Cheyenne Light expiring in 2028, under which we will purchase up to 20 MW of renewable energy through Cheyenne Light's agreement with Happy Jack Wind Farms, LLC; and

- A Generation Dispatch Agreement with Cheyenne Light that requires the Company to purchase all of Cheyenne Light's excess energy.

Long-Term Power Sales Agreements

- The Company has a ten-year power sales contract with MEAN for 20 MW of unit-contingent capacity from the Neil Simpson II plant. The contract expires in 2013; and

- The Company has a power purchase agreement with MDU for the supply of up to 74 MW of capacity and energy for Sheridan, Wyoming from 2007 through 2016. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 MW 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 utility's firm native load.

Legal Proceedings

Ongoing Litigation

The Company is subject to various 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, results of operations or cash flows of the Company.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	2,328,964	2,013,958	-13.53%
6	501 Fuel	16,609,548	19,583,103	17.90%
7	502 Steam Expenses	3,421,379	3,452,359	0.91%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	1,169,326	1,247,588	6.69%
11	506 Miscellaneous Steam Power Expenses	1,207,550	1,300,972	7.74%
12	507 Rents			
13				
14	TOTAL Operation - Steam	24,736,767	27,597,980	11.57%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	485,749	549,213	13.07%
18	511 Maintenance of Structures	190,830	359,668	88.48%
19	512 Maintenance of Boiler Plant	3,402,608	4,676,548	37.44%
20	513 Maintenance of Electric Plant	1,427,906	1,783,555	24.91%
21	514 Maintenance of Miscellaneous Steam Plant	762,523	703,605	-7.73%
22				
23	TOTAL Maintenance - Steam	6,269,616	8,072,589	28.76%
24				
25	**TOTAL Steam Power Production Expenses**	31,006,383	35,670,569	15.04%
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: 2008

	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	54,582	53,453	-2.07%
27	547 Fuel	6,165,421	4,866,665	-21.07%
28	548 Generation Expenses	360,158	352,450	-2.14%
29	549 Miscellaneous Other Power Gen. Expenses	43,804	35,791	-18.29%
30	550 Rents			
31				
32	TOTAL Operation - Other	6,623,965	5,308,359	-19.86%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	74,713	93,202	24.75%
36	552 Maintenance of Structures	5,865	13,625	132.31%
37	553 Maintenance of Generating & Electric Plant	369,976	1,433,268	287.39%
38	554 Maintenance of Misc. Other Power Gen. Plant	23,806	15,012	-36.94%
39				
40	TOTAL Maintenance - Other	474,360	1,555,107	227.83%
41				
42	**TOTAL Other Power Production Expenses**	7,098,325	6,863,466	-3.31%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	49,377,537	80,787,890	63.61%
46	556 System Control & Load Dispatching		635,693	#DIV/0!
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	49,377,537	81,423,583	64.90%
50				
51	**TOTAL Power Production Expenses**	87,482,245	123,957,618	41.69%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	352,284	609,087	72.90%
4	561	Load Dispatching	928,777	656,647	-29.30%
5	562	Station Expenses	42,342	62,497	47.60%
6	563	Overhead Line Expenses	12,607	2,503	-80.15%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	8,162,489	9,466,585	15.98%
9	566	Miscellaneous Transmission Expenses	121,690	201,431	65.53%
10	567	Rents			
11					
12		TOTAL Operation - Transmission	9,620,189	10,998,750	14.33%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	12,498	6,029	-51.76%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	33,503	49,666	48.24%
17	571	Maintenance of Overhead Lines	79,897	100,593	25.90%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21		TOTAL Maintenance - Transmission	125,898	156,288	24.14%
22					
23		**TOTAL Transmission Expenses**	9,746,087	11,155,038	14.46%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	771,641	943,029	22.21%
28	581	Load Dispatching	165,415	178,703	8.03%
29	582	Station Expenses	449,920	462,324	2.76%
30	583	Overhead Line Expenses	467,449	533,525	14.14%
31	584	Underground Line Expenses	216,998	228,638	5.36%
32	585	Street Lighting & Signal System Expenses	136	3,156	2220.59%
33	586	Meter Expenses	245,879	331,448	34.80%
34	587	Customer Installations Expenses	28,911	28,661	-0.86%
35	588	Miscellaneous Distribution Expenses	427,514	545,655	27.63%
36	589	Rents	21,248	22,500	5.89%
37					
38		TOTAL Operation - Distribution	2,795,111	3,277,639	17.26%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	36,060	26,743	-25.84%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	132,647	116,827	-11.93%
43	593	Maintenance of Overhead Lines	1,320,089	1,865,762	41.34%
44	594	Maintenance of Underground Lines	123,311	161,178	30.71%
45	595	Maintenance of Line Transformers	10,591	7,885	-25.55%
46	596	Maintenance of Street Lighting, Signal Systems	137,074	103,418	-24.55%
47	597	Maintenance of Meters	44,403	57,737	30.03%
48	598	Maintenance of Miscellaneous Dist. Plant	31,234	41,573	33.10%
49					
50		TOTAL Maintenance - Distribution	1,835,409	2,381,123	29.73%
51					
52		**TOTAL Distribution Expenses**	4,630,520	5,658,762	22.21%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2008

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	25,934	24,916	-3.93%
4	902 Meter Reading Expenses	454,478	560,035	23.23%
5	903 Customer Records & Collection Expenses	805,187	850,185	5.59%
6	904 Uncollectible Accounts Expenses	335,044	636,748	90.05%
7	905 Miscellaneous Customer Accounts Expenses	597,989	629,010	5.19%
8				
9	TOTAL Customer Accounts Expenses	2,218,632	2,700,894	21.74%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	119,195	125,138	4.99%
14	908 Customer Assistance Expenses	737,854	761,110	3.15%
15	909 Informational & Instructional Adv. Expenses	5,486	7,473	36.22%
16	910 Miscellaneous Customer Service & Info. Exp.	52,019	86,849	66.96%
17				
18	TOTAL Customer Service & Info Expenses	914,554	980,570	7.22%
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	9,759,385	10,109,561	3.59%
32	921 Office Supplies & Expenses	3,673,451	4,951,338	34.79%
33	922 (Less) Administrative Expenses Transferred - Cr.	(32,675)	(26,168)	19.91%
34	923 Outside Services Employed	1,622,012	1,855,011	14.36%
35	924 Property Insurance	673,134	678,709	0.83%
36	925 Injuries & Damages	1,087,181	2,716,385	149.86%
37	926 Employee Pensions & Benefits	937,801	(240,177)	-125.61%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	355,550	349,007	-1.84%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	431,704	401,255	-7.05%
42	930.2 Miscellaneous General Expenses	644,725	455,780	-29.31%
43	931 Rents	262,569	300,919	14.61%
44				
45	TOTAL Operation - Admin. & General	19,414,837	21,551,620	11.01%
46	Maintenance			
47	935 Maintenance of General Plant	286,360	247,843	-13.45%
48				
49	**TOTAL Administrative & General Expenses**	19,701,197	21,799,463	10.65%
50				
51	**TOTAL Operation & Maintenance Expenses**	124,693,235	166,252,345	33.33%

MONTANA TAXES OTHER THAN INCOME

Year: 2008

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	5,550	10,151	82.90%
5	Montana PSC			
6	Franchise Taxes			
7	Property Taxes	59,970	77,024	28.44%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	2,930	6,298	114.95%
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50				
51	**TOTAL MT Taxes Other Than Income**	68,450	93,473	36.56%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts to Montana are not significant.				
2					
3					
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49					
50	**TOTAL Payments for Services**				

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2008

	Description	Total Company	Montana	% Montana
1	None.			
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49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2008

1	Plan Name			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Project Unit Cost Method	IRS Code: 401b		
4	Annual Contribution by Employer: $0.00	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	48,937,283	50,340,250	2.87%
8	Service cost	1,396,277	1,136,624	-18.60%
9	Interest Cost	3,790,488	2,923,207	-22.88%
10	Plan participants' contributions	-		
11	Amendments	(2,032,680)	(2,989,986)	-47.10%
12	Actuarial Gain	2,711,548	(327,933)	-112.09%
13	Acquisition			
14	Benefits paid	(2,838,292)	(2,144,879)	24.43%
15	Benefit obligation at end of year	51,964,624	48,937,283	-5.83%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	52,466,274	46,916,331	-10.58%
18	Actual return on plan assets	(8,770,951)	8,043,709	191.71%
19	Acquisition			
20	Employer contribution			
21	Plan participants' contributions	-	(348,887)	#DIV/0!
22	Benefits paid	(2,249,170)	(2,144,879)	4.64%
23	Fair value of plan assets at end of year	41,446,153	52,466,274	26.59%
24	**Funded Status**	(19,864,195)	3,528,991	117.77%
25	Unrecognized net actuarial loss	25,836,272	2,438,518	-90.56%
26	Unrecognized prior service cost	419,809	559,743	33.33%
27	Prepaid (accrued) benefit cost	6,391,886	6,527,252	2.12%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	6.35%	5.95%	-6.30%
31	Expected return on plan assets	8.50%	8.50%	
32	Rate of compensation increase	4.34%	4.31%	-0.69%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	1,117,021	1,136,624	1.75%
36	Interest cost	3,032,391	2,923,207	-3.60%
37	Expected return on plan assets	(4,374,194)	(3,884,977)	11.18%
38	Amortization of prior service cost	111,947	103,361	-7.67%
39	Recognized net actuarial loss	-	407,501	#DIV/0!
40	Net periodic benefit cost	(112,835)	685,716	707.72%
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	1,027	961	-6.43%
48	Not Covered by the Plan	46	42	-8.70%
49	Active	623	569	-8.67%
50	Retired	181	178	-1.66%
51	Deferred Vested Terminated	177	172	-2.82%

Other Post Employment Benefits (OPEBS)

Year: 2008

	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%	5.95%	-6.30%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	10.00%	9.00%	-10.00%
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	#VALUE!
11	Rate of compensation increase	4.34	4.31%	-99.01%
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	6,991,384	6,542,546	-6.42%
20	Service cost	216,075	210,670	-2.50%
21	Interest Cost	444,132	398,195	-10.34%
22	Plan participants' contributions			
23	Amendments			
24	Actuarial Gain	50,934	50,934	
25	Acquisition			
26	Benefits paid	(581,289)	(210,961)	63.71%
27	Benefit obligation at end of year	7,121,236	6,991,384	-1.82%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	(210,961)	-	100.00%
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution			
33	Plan participants' contributions	-	-	
34	Benefits paid	(581,289)	(210,961)	63.71%
35	Fair value of plan assets at end of year	(792,250)	(210,961)	73.37%
36	**Funded Status**	(7,913,486)	(7,202,345)	8.99%
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost	(7,913,486)	(7,202,345)	8.99%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	216,075	210,670	-2.50%
42	Interest cost	444,132	398,195	-10.34%
43	Expected return on plan assets	-	-	
44	Amortization of prior service cost			
45	Recognized net actuarial loss	50,934	50,934	
46	Net periodic benefit cost	711,141	659,799	-7.22%
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: 2008

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	812	760	-6.40%
3	Not Covered by the Plan			
4	Active	617	568	-7.94%
5	Retired	102	102	
6	Spouses/Dependants covered by the Plan	93	90	-3.23%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost			
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ________________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

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

SCHEDULE 16

Year: 2008

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							

Company Name: Black Hills Power, Inc.

SCHEDULE 17

Year: 2008

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						
2	Anthony S. Clegerg Executive Vice President and Chief Financial Officer						
3	Thomas M. Ohlmacher President and Chief Operating Officer Non-regulated Energy						
4	Linden R. Evans President and Chief Operating Officer- Utilities						
5	Steven J. Helmers Senior Vice President- General Counsel and Corporate Compliance Officer						
	*PLEASE REFER TO THE EXCERPTS FROM THE BHC ANNUAL MEETING OF SHAREHOLDERS AND PROXY STATEMENT ATTACHED AS SCHEDULE 17A						

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the fiscal years ended December 31, 2008, 2007 and 2006. We have no employment agreements with our Named Executive Officers. Amounts listed under the heading "Non-Equity Incentive Plan Compensation" represent amounts earned under the Short-Term Annual Incentive Plan for each year. The Compensation Committee approved the payout of the 2008 awards at its January 29, 2009, meeting and the awards were paid on March 6, 2009.

Based on the fair value of equity awards granted to our Named Executive Officers in 2008 and the base salary of our Named Executive Officers, base salary accounted for 36 percent to 51 percent of total compensation, short-term annual incentive accounted for 18 percent to 25 percent of total compensation and long-term incentive accounted for 31 percent to 42 percent of total compensation. Because the table below reflects the value of certain equity awards based on the Statement of Financial Accounting Standards 123(R), "Share-Based Payment," ("FAS 123(R)") value rather than the fair value, these percentages cannot be derived using the amounts reflected in the table below.

Name and Principal Position	Year	Salary	Bonus(1)	Stock Awards(2)	Option Awards(3)	Non-Equity Incentive Plan Compensation(4)	Change in Pension Value and Non-qualified Deferred Compensation Earnings(5)	All Other Compensation(6)	Total
David R. Emery . . .	2008	$563,269	—	$ 348,766	—	$205,296	$549,730	$ 42,293	$1,709,354
Chairman,	2007	$544,231	—	$ 921,030	—	$763,000	$312,524	$ 36,583	$2,577,368
President and Chief Executive Officer	2006	$524,039	—	$ 327,766	$14,551	$551,250	$249,828	$ 40,276	$1,707,710
Anthony S. Cleberg . Executive Vice President and Chief Financial Officer	2008	$130,846	—	$ 31,248	—	$ 34,020	$ 3,645	$ 25,911	$ 225,670
Mark T. Thies	2008	$ 36,365	—	$(125,043)	—	—	$140,511	$372,198	$ 424,031
Former Executive	2007	$288,377	—	$ 390,408	—	$230,960	$ 19,058	$ 19,776	$ 948,579
Vice President and Chief Financial Officer(7)	2006	$279,885	—	$ 153,680	$14,239	$168,180	$ 55,459	$ 31,969	$ 703,412
Thomas M. Ohlmacher	2008	$350,600	—	$ 82,441	—	$ 91,260	$292,809	$ 28,915	$ 846,025
President and	2007	$340,600	—	$ 766,103	—	$340,600	$ 13,645	$ 26,103	$1,487,051
Chief Operating Officer— Non-regulated Energy	2006	$340,219	$32,000	$ 405,299	$34,085	$255,450	$223,970	$ 35,574	$1,326,597
Linden R. Evans . . .	2008	$273,212	—	$ 145,811	—	$ 71,240	$125,292	$ 24,421	$ 639,976
President and	2007	$253,035	—	$ 432,649	—	$253,500	$ 53,952	$ 20,166	$1,013,302
Chief Operating Officer—Utilities	2006	$240,712	—	$ 151,114	$12,748	$181,050	$ 10,802	$ 20,088	$ 616,514
Steven J. Helmers . .	2008	$269,604	—	$ 99,757	—	$ 49,140	$121,460	$ 21,648	$ 561,609
Senior Vice	2007	$259,408	—	$ 296,868	—	$181,790	$ 54,414	$ 15,231	$ 807,711
President and General Counsel	2006	$251,819	—	$ 115,168	$ 9,612	$132,353	$109,035	$ 17,322	$ 635,309

(1) Mr. Ohlmacher's 2006 bonus reflects a $32,000 relocation bonus to compensate for additional state income taxes.

(2) Stock Awards represent the annual compensation expense related to restricted stock, restricted stock units and performance shares that have been granted as a component of Long-Term Incentive Compensation. The amount reported is the amount recognized for financial statement reporting purposes computed in accordance with

FAS 123(R), and therefore includes amounts for awards granted in prior years. Assumptions used in the calculation of these amounts are included in Note 10 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008.

Mr. Thies terminated employment in January 2008 and forfeited 2,970 shares of restricted stock and 5,796 target performance shares. Previously recorded compensation expense associated with these awards in the amount of $125,043 was reversed in accordance with FAS 123(R).

Mr. Ohlmacher turned age 55 in September 2006 which made him eligible for early retirement. Because our restricted stock and restricted stock units granted prior to December 10, 2007 fully vest at retirement, the fair value of $190,000 associated with Mr. Ohlmacher's awards granted in each of 2007 and 2006 was all recognized in the year of grant in accordance with FAS 123(R), rather than expensing the award over the normal three year vesting period.

(3) Option Awards represent the annual compensation expense related to stock options that have been granted as a component of Long-Term Incentive Compensation in prior years. The amount reported is the amount recognized for financial statement reporting purposes computed in accordance with FAS 123(R), and therefore includes amounts for awards granted in prior years. Assumptions used in the calculation of these amounts are included in Note 10 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008.

(4) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Annual Incentive Plan.

(5) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the increase in actuarial value of the Defined Benefit Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective year. The amounts for 2008 have been annualized due to the change in FAS 87 measurement date. The change in present value of the accumulated benefit from September 30, 2007 to December 31, 2008 has been multiplied by 12/15ths to determine a twelve month value (except for Messrs. Cleberg and Thies who did not accrue benefits for the entire 15 month period).

The PEP is offered through the Grandfathered Pension Equalization Plan ("Grandfathered PEP"), 2005 Pension Equalization Plan ("2005 PEP") and 2007 Pension Equalization Plan ("2007 PEP"). No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The value attributed from each plan to each Named Executive Officer is shown in the table below. Mr. Evans was not a participant in the PRB in 2007 and 2006. Messrs. Emery, Thies, Ohlmacher and Helmers are participants in the Grandfathered PEP and 2005 PEP. Messrs. Cleberg and Evans are the only Named Executive Officers participating in the 2007 PEP.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2008	$ 33,858	$264,299	$251,573	$549,730
	2007	$ 6,366	$159,889	$146,269	$312,524
	2006	$ 13,444	$116,786	$119,598	$249,828
Anthony S. Cleberg	2008	—	$ 3,645	—	$ 3,645
Mark T. Thies	2008	$ 17,844	$ 34,908	$ 87,759	$140,511
	2007	$ 6,897	$ 9,195	$ 2,966	$ 19,058
	2006	$ 11,200	$ 16,192	$ 28,067	$ 55,459
Thomas M. Ohlmacher	2008	$101,389	$109,258	$ 82,162	$292,809
	2007	$ 36,675	$(18,858)	$ (4,172)	$ 13,645
	2006	$ 49,308	$109,399	$ 65,263	$223,970
Linden R. Evans	2008	$ 19,368	$ 48,132	$ 57,792	$125,292
	2007	$ 14,958	—	$ 38,994	$ 53,952
	2006	$ 10,802	—	—	$ 10,802
Steven J. Helmers	2008	$ 26,157	$ 22,526	$ 72,777	$121,460
	2007	$ 13,460	$ 13,020	$ 27,934	$ 54,414
	2006	$ 20,172	$ 16,389	$ 72,474	$109,035

(6) All Other Compensation includes amounts allocated under the 401(k) match, dividends received on restricted stock and unvested restricted stock units and perquisites. Perquisites provided to our Named Executive Officers include personal use of a Company vehicle and financial planning services for each year and club dues in 2006 only. Mr. Cleberg's 2008 perquisites also include temporary living, travel and other relocation expenses.

	Year	Severance	401(k) Match	Dividends on Restricted Stock/Units	Total Perquisites	Total Other Compensation
David R. Emery	2008	—	$6,900	$26,496	$ 8,897	$ 42,293
Anthony S. Cleberg	2008	—	$3,925	$ 4,796	$17,190	$ 25,911
Mark T. Thies	2008	$364,067	$6,900	—	$ 1,231	$372,198
Thomas M. Ohlmacher	2008	—	$6,900	$15,235	$ 6,780	$ 28,915
Linden R. Evans	2008	—	$6,900	$11,780	$ 5,741	$ 24,421
Steven J. Helmers	2008	—	$6,900	$ 8,037	$ 6,711	$ 21,648

(7) Mr. Thies resigned from the Company on January 18, 2008. Mr. Thies's severance agreement is disclosed under the caption "Severance Agreement."

GRANTS OF PLAN BASED AWARDS IN 2008(1)

Name	Grant Date	Date of Compensation Committee Action	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(2) Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards(3) Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units(4) (#)	Grant Date Fair Value of Stock Awards(5) ($)
David R. Emery			$118,440	$394,800	$789,600					
	1/01/08	12/10/07				3,450	6,900	12,075		$317,400
	1/04/08	12/10/07							7,170	$299,993
	8/13/08	7/28/08							7,613	$250,010
Anthony S. Cleberg(6)			$ 19,561	$ 65,205	$130,410	—	—	—		
	8/13/08	7/07/08							6,851	$224,986
Thomas M. Ohlmacher			$ 52,650	$175,500	$351,000					
	1/01/08	12/10/07				2,185	4,370	7,648		$201,020
	1/04/08	12/10/07							4,541	$189,995
	8/13/08	7/28/08							2,284	$ 75,006
Linden R. Evans			$ 41,100	$137,000	$274,000					
	1/01/08	12/10/07				1,374	2,748	4,809		$126,408
	1/04/08	12/10/07							2,856	$119,495
	8/13/08	7/28/08							4,568	$150,013
Steven J. Helmers			$ 28,350	$ 94,500	$189,000					
	1/01/08	12/10/07				925	1,850	3,237		$ 85,100
	1/04/08	12/10/07							1,923	$ 80,458
	8/13/08	7/28/08							3,045	$ 99,997

(1) No stock options were granted to our Named Executive Officers in 2008. Mr. Thies received no grants of plan based awards in 2008.

(2) The columns under "Estimated Possible Payouts Under Non-Equity Incentive Plan Awards" show the range of payouts for 2008 performance under the Short-Term Annual Incentive Compensation Program as described in the Compensation Discussion and Analysis under the section titled "Annual Incentive." If the performance criteria is met, payouts can range from 30 percent of target at the threshold level to 200 percent of target at the maximum level. The 2009 bonus payment for 2008 performance has been made based on achieving the criteria described in the Compensation Discussion and Analysis, at 52 percent of target, and is shown in the Summary Compensation Table in the column titled "Non-Equity Incentive Plan Compensation."

(3) The columns under "Estimated Future Payouts Under Equity Incentive Plan Awards" show the range of payouts (in shares of stock) for the January 1, 2008 to December 31, 2010 performance period as described in the Compensation Discussion and Analysis under the section titled "Long-Term Incentive—*Performance Shares*." If the performance criteria are met, payouts can range from 50 percent of target to 175 percent of target. If a participant retires, suffers a disability or dies

during the performance period, the participant or the participant's estate is entitled to that portion of the number of performance shares as such participant would have been entitled to had he or she remained employed, prorated for the number of months served. Performance shares are forfeited if employment is terminated for any other reason. During the performance period, dividends and other distributions paid with respect to the shares of common stock shall accrue for the benefit of the participant and are paid out at the end of the performance period.

(4) The column "All Other Stock Awards" reflects the number of shares of restricted stock granted on January 4, 2008 and August 13, 2008 under our 2005 Omnibus Incentive Plan. The restricted stock vests one-third a year over a three-year period, and automatically vests upon death, disability or a change in control. Unvested restricted stock is forfeited if employment is terminated for any other reason. Dividends are paid on the restricted shares and the dividends that were paid in 2008 are included in the column titled "All Other Compensation" in the Summary Compensation Table.

(5) The column "Grant Date Fair Value of Stock Awards" reflects the grant date fair value of each equity award computed in accordance with FAS 123(R). The grant date fair value for the performance shares was $46.00 per share and was calculated using a Monte Carlo simulation model. Assumptions used in the calculation are included in Note 10 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008. The grant date fair value for the restricted stock was $41.84 per share for the January 4, 2008 grant and $32.84 per share for the August 13, 2008 grant which was the market value of our common stock on the respective date of grant as reported on the New York Stock Exchange.

(6) Mr. Cleberg's awards reflect a partial year of service.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2008(1)

	Option Awards			Stock Awards			
Name	Number of Securities Underlying Unexercised Options Exercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested(2) (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(2) (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
David R. Emery	8,000	$24.0625	7/20/09	22,732	$612,855	7,532	$203,049
	30,000	$21.8750	4/25/10				
	5,000	$55.3600	5/30/11				
	4,595	$35.1000	4/23/12				
	7,500	$27.4900	3/31/13				
	13,787	$28.0900	5/15/13				
Anthony S. Cleberg	—	—	—	6,851	$184,703	—	—
Thomas M. Ohlmacher	2,500	$55.3600	5/30/11	12,024	$324,167	4,770	$128,599
Linden R. Evans	2,000	$32.3400	6/17/12	10,698	$288,418	3,000	$ 80,880
	3,000	$25.1600	12/10/12				
	5,000	$29.8300	12/31/13				
Steven J. Helmers	9,000	$55.3600	5/30/11	7,263	$195,810	2,020	$ 54,446
	10,110	$35.1000	4/23/12				

(1) There were no unexercisable stock options or unexercised unearned options under equity incentive plans outstanding at December 31, 2008 for our Named Executive Officers. Mr. Thies had no outstanding equity awards at December 31, 2008.

BALANCE SHEET

Year: 2008

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	664,721,390	688,051,242	-3%
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	13,982,118	12,943,074	8%
9	107	Construction Work in Progress - Electric	19,018,220	144,966,114	-87%
10	108	(Less) Accumulated Depreciation	(279,711,936)	(297,391,540)	6%
11	111	(Less) Accumulated Amortization			
12	114	Electric Plant Acquisition Adjustments	4,870,308	4,870,308	
13	115	(Less) Accum. Amort. Elec. Acq. Adj.	(2,523,403)	(2,674,807)	6%
14	120	Nuclear Fuel (Net)			
15		**TOTAL Utility Plant**	420,356,697	550,764,391	-24%
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	3,934,711	4,146,216	-5%
23	125	Sinking Funds			
24		**TOTAL Other Property & Investments**	3,936,373	4,147,878	-5%
25					
26	**Current & Accrued Assets**				
27	131	Cash	2,028,950		#DIV/0!
28	132-134	Special Deposits			
29	135	Working Funds	4,175	4,175	
30	136	Temporary Cash Investments			
31	141	Notes Receivable	12,626	14,335	-12%
32	142	Customer Accounts Receivable	16,565,623	18,577,176	-11%
33	143	Other Accounts Receivable	2,198,228	2,113,486	4%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(388,368)	(370,000)	-5%
35	145	Notes Receivable - Associated Companies	10,304,111		#DIV/0!
36	146	Accounts Receivable - Associated Companies	8,882,287	12,619,270	-30%
37	151	Fuel Stock	4,025,206	7,336,132	-45%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals			
40	154	Plant Materials and Operating Supplies	11,525,086	11,861,073	-3%
41	155	Merchandise			
42	156	Other Material & Supplies			
43	157	Nuclear Materials Held for Sale			
44	163	Stores Expense Undistributed	77,553	112,032	-31%
45	165	Prepayments	6,173,396	1,308,218	372%
46	171	Interest & Dividends Receivable			
47	172	Rents Receivable			
48	173	Accrued Utility Revenues	5,776,556	5,390,697	7%
49	174	Miscellaneous Current & Accrued Assets	238,315		#DIV/0!
50		**TOTAL Current & Accrued Assets**	67,423,744	58,966,594	14%

BALANCE SHEET

Year: 2008

	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	1,361,760	1,289,597	6%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	183	Prelim. Survey & Investigation Charges	616,078	1,035,817	-41%
10	184	Clearing Accounts	404,419	309,222	31%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	233,455	370,257	-37%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	2,527,308	2,366,830	7%
16	190	Accumulated Deferred Income Taxes	15,569,776	52,085,180	-70%
17		**TOTAL Deferred Debits**	20,712,796	57,456,903	-64%
18					
19		**TOTAL Assets & Other Debits**	512,429,610	671,335,766	-24%
		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	42,076,811	42,076,811	
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	170,705,475	193,281,126	-12%
35	217	(Less) Reacquired Capital Stock	(1,277,097)	(1,348,641)	5%
36		**TOTAL Proprietary Capital**	232,419,703	254,923,810	-9%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	131,410,000	129,455,000	2%
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies			
43	224	Other Long Term Debt	21,807,473	21,753,899	0%
44	225	Unamortized Premium on Long Term Debt			
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.			
46		**TOTAL Long Term Debt**	153,217,473	151,208,899	1%

BALANCE SHEET

Year: 2008

	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	12,474,695	25,567,740	-51%
18	233	Notes Payable to Associated Companies		70,183,866	-100%
19	234	Accounts Payable to Associated Companies	3,158,380	10,411,146	-70%
20	235	Customer Deposits	636,712	669,713	-5%
21	236	Taxes Accrued	4,575,823	4,992,767	-8%
22	237	Interest Accrued	3,440,329	3,447,977	0%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	506,879	999,640	-49%
27	242	Miscellaneous Current & Accrued Liabilities	4,567,290	6,307,393	-28%
28	243	Obligations Under Capital Leases - Current	67,815		#DIV/0!
29		**TOTAL Current & Accrued Liabilities**	29,427,923	122,580,242	-76%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	4,832,708	4,680,710	3%
34	253	Other Deferred Credits	15,186,557	35,215,645	-57%
35	255	Accumulated Deferred Investment Tax Credits	307,159	237,988	29%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	77,038,087	102,488,472	-25%
39		**TOTAL Deferred Credits**	97,364,511	142,622,815	-32%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		512,429,610	671,335,766	-24%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2008

	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: 2008

	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	445,583	445,583	
37	363 Storage Battery Equipment			
38	364 Poles, Towers & Fixtures	378,873	388,761	-3%
39	365 Overhead Conductors & Devices	415,751	415,751	
40	366 Underground Conduit	909	909	
41	367 Underground Conductors & Devices	15,834	15,834	
42	368 Line Transformers	43,484	44,307	-2%
43	369 Services	3,367	3,367	
44	370 Meters	6,278	15,981	-61%
45	371 Installations on Customers' Premises			
46	372 Leased Property on Customers' Premises			
47	373 Street Lighting & Signal Systems			
48				
49	**TOTAL Distribution Plant**	1,342,353	1,362,767	

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

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2008

	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**		1,357,085	1,377,499	

MONTANA DEPRECIATION SUMMARY

Year: 2008

	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	1,336,463	352,243	220,280	
8	General	14,732	6,712	10,031	
9	**TOTAL**	1,351,195	358,955	230,311	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

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

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	83.4.25			
2	Order Number	4998			
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		62.77%		
13	Preferred Stock		37.23%		
14	Long Term Debt				
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2008

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	24,895,901	22,759,259	9%
6	Depreciation	20,611,646	20,778,346	-1%
7	Amortization	455,770	448,376	2%
8	Deferred Income Taxes - Net	4,097,594	16,141,109	-75%
9	Investment Tax Credit Adjustments - Net	(233,329)	(69,171)	-237%
10	Change in Operating Receivables - Net	(11,099,489)	(5,298,011)	-110%
11	Change in Materials, Supplies & Inventories - Net	1,950,699	(3,681,392)	153%
12	Change in Operating Payables & Accrued Liabilities - Net	(6,459,477)	9,742,252	-166%
13	Allowance for Funds Used During Construction (AFUDC)	(601,108)	(3,604,543)	83%
14	Change in Other Assets & Liabilities - Net	(22,589,458)	(11,122,920)	-103%
15	Other Operating Activities (explained on attached page)			
16	**Net Cash Provided by/(Used in) Operating Activities**	11,028,749	46,093,305	-76%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(10,967,350)	(126,206,543)	91%
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	2,959,500		#DIV/0!
24	Contributions and Advances from Affiliates		80,487,977	-100%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained below *)	(209,106)	(211,505)	1%
27	**Net Cash Provided by/(Used in) Investing Activities**	(8,216,956)	(45,930,071)	82%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt			
32	Preferred Stock			
33	Common Stock			
34	Other:			
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(2,001,756)	(2,008,575)	0%
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			
45	Other Financing Activities (explained below **)		(183,609)	100%
46	**Net Cash Provided by (Used in) Financing Activities**	(2,001,756)	(2,192,184)	9%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	810,037	(2,028,950)	140%
49	**Cash and Cash Equivalents at Beginning of Year**	1,223,088	2,033,125	-40%
50	**Cash and Cash Equivalents at End of Year**	2,033,125	4,175	48598%

*Long Term Notes Receivable, Officer Insurance, PEP Insurance CSV
**Cumulative effect accounting adjustment for Pension

LONG TERM DEBT

Year: 2008

	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	2,810,000	9.49%	283,558	10.09%
2									
3	Series Z	05/1991	05/2021	35,000,000	34,790,305	21,645,000	9.35%	2,095,663	9.68%
4									
5	Series AC	02/1995	02/2010	30,000,000	29,812,500	30,000,000	8.06%	2,148,000	7.16%
6									
7	Series AE	08/2002	08/2032	75,000,000	74,343,750	75,000,000	7.23%	5,455,581	7.27%
8									
9	2004 Pollution Control:								
10	Campbell Cty 4.8%	11/2004	10/2014	1,550,000	1,532,563	1,550,000	4.80%	148,800	9.60%
11	Campbell Cty 5.35%	11/2004	10/2024	12,200,000	12,062,750	12,200,000	5.35%	665,560	5.46%
12	Pennington Cty 4.8%	11/2004	10/2014	2,050,000	2,026,938	2,050,000	4.80%	102,777	5.01%
13	Weston Cty 4.8%	11/2004	10/2014	2,850,000	2,817,938	2,850,000	4.80%	142,885	5.01%
14									
15	1994 A Environ Improv Bond	06/1994	06/2024	3,000,000	2,930,057	2,855,000	6.07%	176,529	6.18%
16									
17	Bear Paw Energy	06/2000	05/2012	1,078,000	1,078,000	248,899	13.66%	38,130	15.32%
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			168,728,000	167,301,379	151,208,899		11,257,484	7.44%

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

SCHEDULE 25

PREFERRED STOCK

Year: 2008

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	N/A									
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
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27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2008

		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 - Black Hills Corp								
3									
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: 2008

	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 complete because			
31	Montana revenues represent less than			
32	1% of the Company's revenue.			
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: 2008

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,377
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	(230)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	1,147
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	2,076
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	2,076
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	2,076
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	21
37		Industrial	1
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	35
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	88,008
45		Average Annual Residential Cost per (Kwh) (Cents) *	8.42
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	586
48		Gross Plant per Customer	32.77

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

SCHEDULE 29

MONTANA CUSTOMER INFORMATION

Year: 2008

	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						
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31						
32	**TOTAL Montana Customers**					

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

MONTANA EMPLOYEE COUNTS

Year: 2008

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

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

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2009

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
9			
10			
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47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2008

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	21	1900	361	290,495	81,700
2	Feb.	9	1900	336	274,683	81,500
3	Mar.	6	2000	314	294,382	108,201
4	Apr.	1	800	295	291,734	122,436
5	May	10	1100	288	286,162	112,425
6	Jun.	30	1800	351	271,342	92,589
7	Jul.	30	1600	395	291,609	87,227
8	Aug.	1	1700	409	287,641	85,030
9	Sep.	17	1700	305	274,142	112,829
10	Oct.	27	800	296	312,896	137,089
11	Nov.	20	1900	321	298,411	117,100
12	Dec.	15	1800	407	331,038	111,341
13	**TOTAL**				3,504,535	1,249,467

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.					
16	Mar.	*Peak information maintained on a total system basis only.				
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	1,731,839	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,672,933
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	61,809	for Resale	490,733
7	(Less) Energy for Pumping			
8	**NET Generation**	1,793,648	Non-Requirements Sales	
9	Purchases	1,732,758	for Resale	1,249,467
10	Power Exchanges			
11	Received	50,554	Energy Furnished	
12	Delivered	(71,467)	Without Charge	
13	**NET Exchanges**	(20,913)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	3,361,350	Electric Utility	11,854
16	Delivered	(3,347,729)		
17	**NET Transmission Wheeling**	13,621	Total Energy Losses	79,548
18	Transmission by Others Losses	(14,579)		
19	**TOTAL**	3,504,535	**TOTAL**	3,504,535

SOURCES OF ELECTRIC SUPPLY

Year: 2008

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	2,717
2					
3	Thermal	Ben French	Rapid City, SD	10	(275)
4					
5	Thermal	Ben French	Rapid City, SD	24	120,568
6					
7	Thermal	Osage	Osage, WY	35	222,052
8					
9	Thermal	Wyodak	Gillette, WY	69	558,803
10					
11	Thermal	Neil Simpson I	Gillette, WY	20	139,836
12					
13	Thermal	Neil Simpson II	Gillette, WY	84	690,576
14					
15	Thermal	Lange	Rapid City, SD	39	24,780
16					
17	Thermal	Neil Simpson CT 1	Gillette, WY	39	34,782
18					
19	Purchases	See Schedule 32			1,732,758
20					
21	Wheeling	See Schedule 32			13,621
22					
23	Total Interchange	See Schedule 32			(20,913)
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**			418	3519305

Company Name: Black Hills Power, Inc.

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2008

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

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	N/A					
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	N/A					
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: 2008

	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	$7,622	$7,013	91	85	13	13
2	Commercial - Small	64,443	70,462	767	853	21	20
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	2,004,360	1,474,385	38,839	28,865	1	2
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**	$2,076,425	$1,551,861	39,697.1	29,803.0	35	35