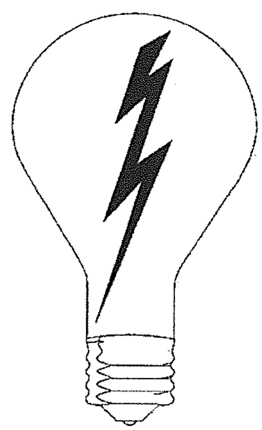
YEAR ENDING 2011

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

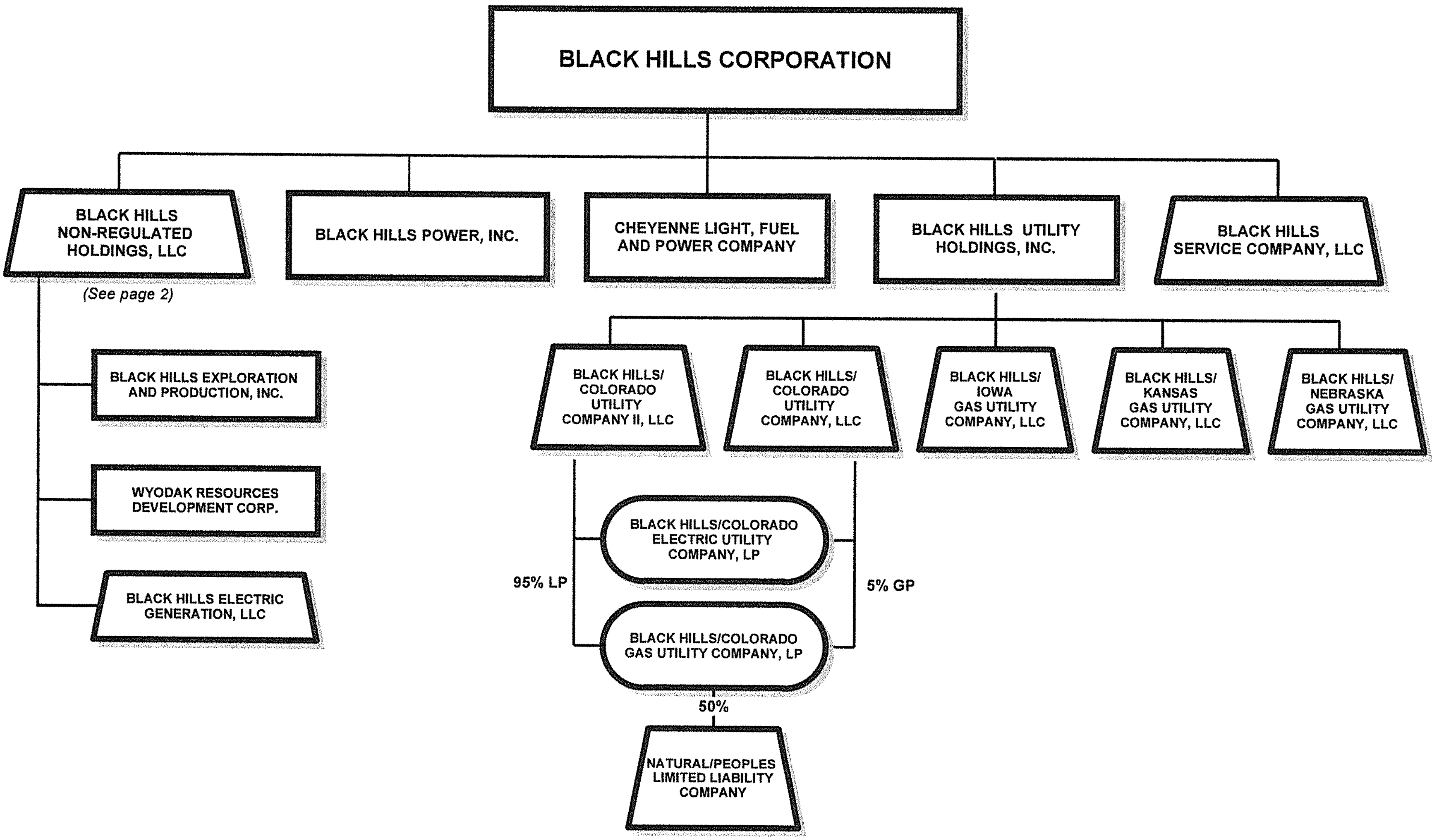
Electric Annual Report

Table of Contents

continued on next page

Last Update: 03-01-12

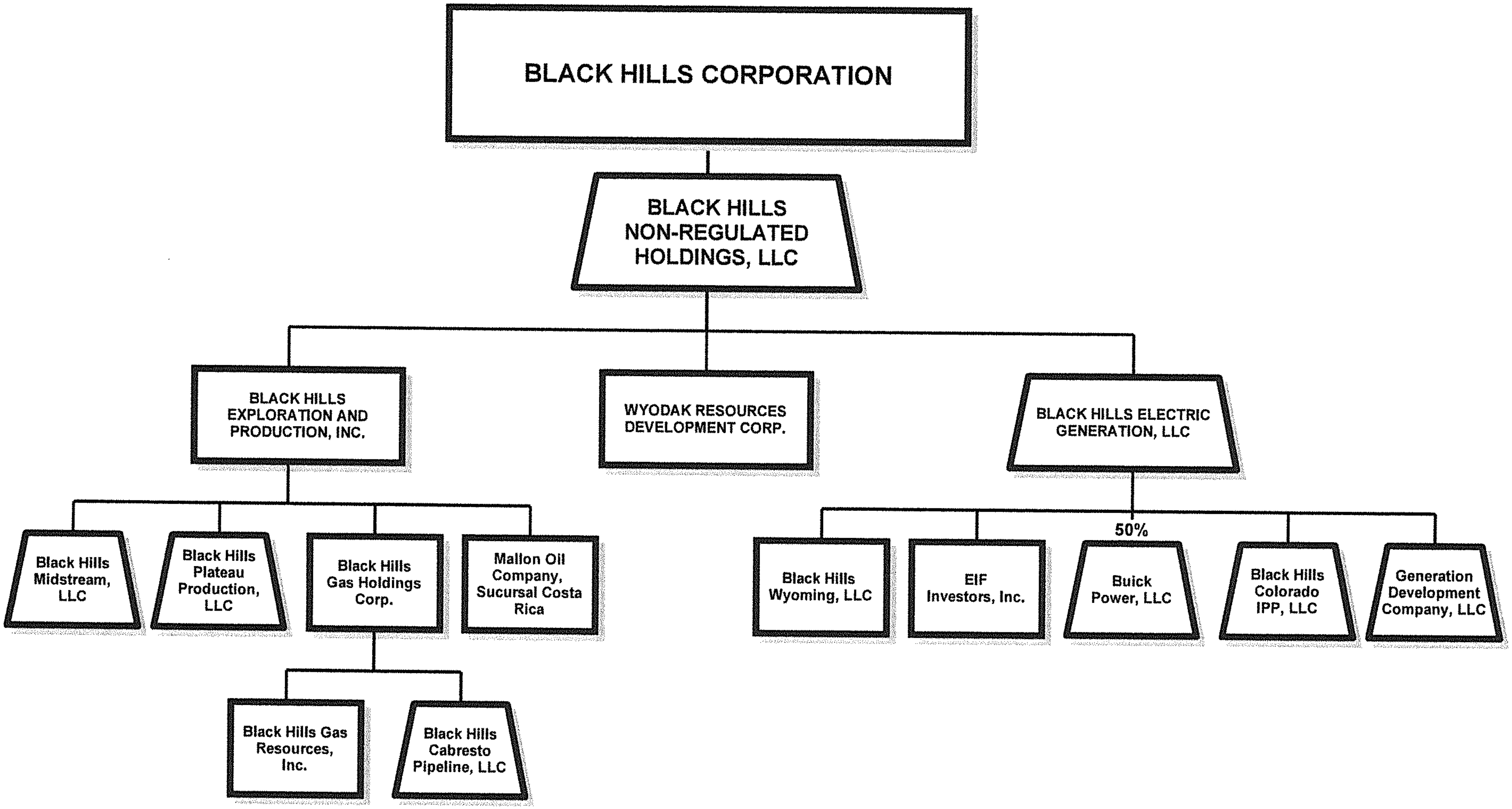
BLACK HILLS CORPORATION ORGANIZATIONAL CHART



○ Doing business as *BLACK HILLS ENERGY*

Last Update: 03-01-12

BLACK HILLS CORPORATION ORGANIZATIONAL CHART



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

IDENTIFICATION

Year: **2011**

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 - Resource Planning and Electric Rates
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	David C. Ebertz	Gillette, WY	$70,500
3	Jack W. Eugster	Excelsior, MN	80,000
4	John R. Howard	Rapid City, SD	70,500
5	Kay S. Jorgensen (b)	Spearfish, SD	29,000
6	Steven R. Mills (c)	Monticello, IL	18,000
7	Stephen D. Newlin	Westlake, OH	81,000
8	Gary L. Pechota	Bethlehem, PA	73,500
9	Rebecca B. Roberts (c)	The Woodlands, TX	46,500
10	Warren L. Robinson	Rapid City, SD	80,500
11	John B. Vering (d)	Southlake, TX	
12	Thomas J. Zeller	Rapid City, SD	87,000
13			
14	(a) Mr. Emery is an officer of the company and is not compensated for his services as a director.		
15	(b) Ms. Jorgensen's term as a member of our Board of Directors concluded May 25, 2011.		
16	(c) Ms. Roberts and Mr. Mills became members of our Board of Directors effective May 25, 2011 and		
17	October 26, 2011, respectively.		
18	(d) Mr. Vering served as Interim President and General Manager of our oil and gas subsidiary from May		
19	2010 until December 2011. He was not compensated for his services as a director during that time.		
20			

Officers

Year: 2011

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, General Counsel, and CCO		Steven J. Helmers
5	Senior Vice President - Chief Information Officer		Scott A. Buchholz
6	Senior Vice President - Communication and Investor Relations		Lynnette K. Wilson
7	Senior Vice President - Human Resources		Robert A. Myers
8	Vice President - Governance and Corporate Secretary		Roxann R. Basham
9	Vice President - Strategic Initiatives		Stephen L. Pella
10	Vice President - Supply Chain		Perry S. Krush
11	Vice President - Corporate Controller		Jeffrey B. Berzina
12	Vice President - Chief Risk Officer		Garner M. Anderson (a)
13	Vice President - Resource Planning and Regulatory Affairs		Kyle D. White (b)
14	Vice President - Strategic Planning & Development		Richard W. Kinzley
15	Vice President - Utility Operations		Stuart A. Wevik
16	Vice President - Utility Services		Ivan Vancas
17	Vice President and General Manager - Power Delivery		Mark L. Lux
18	Vice President and General Manager - Gillette Complex		Gregory L. Hager
19	Vice President - Customer Service		Randy D. Winkelman
20	Vice President - BHP Operations		Richard C. Loomis
21	Vice President - Treasurer		Brian G. Iverson (c)
22	Vice President - Elec Regulatory Services and Sr. Corporate Counsel		Wendy M. Moser (d)
23			
24			
25			
26	(a) Garner M. Anderson's position changed to Vice President- Chief Risk Officer in March 2011.		
27			
28	(b) Kyle D. White's position changed to Vice President- Resource Planning and Regulatory Affairs in		
29	March 2011.		
30			
31	(c) Brian G. Iverson's position changed to Vice President- Treasurer in March 2011.		
32			
33	(d) Wendy M. Moser was appointed Vice President- Electric Regulatory Services and Senior Corporate		
34	Counsel in October 2011.		
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			

CORPORATE STRUCTURE

Year: 2011

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	27,097,056	100.00%
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				100.00%
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL**		27,097,056	

CORPORATE ALLOCATIONS

Year: 2011

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2011

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)	16,447,596	24.59%	463,822
2	Enserco Energy, Inc	Gas Sales to Utility	Fair Market Value (based on similar arms-length transactions)	223,086	0.05%	6,291
3	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	9,363,078	7.27%	264,039
4	Black Hills Service Company	Information Technology, General Accounting, Insurance, Regulatory and Governmental Services, Facilities, Various Other Non-power Goods and Services	Fair Market Value (Based on similar arms-length transactions). Indirect charges were allocated based on Black Hills Service Company Cost Allocation Manual	18,025,526	39.72%	508,320
5	Black Hills Utility Holding Company	Various Non-power Goods and Services	Fair Market Value (Based on similar arms-length transactions). Indirect charges were allocated based on Black Hills Utility Holding Company Cost Allocation Manual	2,392,235	16.25%	67,461
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	**TOTAL**			46,451,521		1,309,933

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2011

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	1,389,900	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point Open Access Transmission Tariff	1,078,948	100.00%	
3	Cheyenne Light Fuel and Power	Transmission Service	Point to Point Open Access Transmission Tariff	570,372	0.73%	16,084
4	Black Hills Wyoming	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	9,004	100.00%	
5	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (Based on similar arms-length transactions)	956,780	1.23%	26,981
6	Black Hills Colorado Electric	Generation Support	Fair Market Value (based on similar arms-length transactions)	1,173,525	0.78%	33,093
7	Cheyenne Light Fuel and Power	Generation Support	Fair Market Value (based on similar arms-length transactions)	349,514	0.45%	9,856
8	Cheyenne Light Fuel and Power	Generation Support	Fair Market Value (based on similar arms-length transactions)	5,336,814	6.85%	150,498
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24	**TOTAL**			10,864,857		236,513

MONTANA UTILITY INCOME STATEMENT

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	230,227,106	244,881,027	6.36%
2					
3		Operating Expenses			
4	401	Operation Expenses	137,448,652	142,987,748	4.03%
5	402	Maintenance Expense	14,330,107	15,879,385	10.81%
6	403	Depreciation Expense	21,886,431	27,119,597	23.91%
7	404-405	Amortization of Electric Plant	32,286		-100.00%
8	406	Amort. of Plant Acquisition Adjustments	110,906	97,406	-12.17%
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs	739,444		-100.00%
11	408.1	Taxes Other Than Income Taxes	6,603,929	4,827,516	-26.90%
12	409.1	Income Taxes - Federal	(14,896,058)	14,718,322	198.81%
13		- Other	5,613	(5,063)	-190.20%
14	410.1	Provision for Deferred Income Taxes	55,238,969	31,324,586	-43.29%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(29,514,065)	(34,241,832)	-16.02%
16	411.4	Investment Tax Credit Adjustments	(99,324)	(14,266)	85.64%
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**	191,886,890	202,693,399	5.63%
21		**NET UTILITY OPERATING INCOME**	38,340,216	42,187,628	10.03%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	7,600	6,700	-11.84%
3	442	Commercial & Industrial - Small	55,800	41,900	-24.91%
4		Commercial & Industrial - Large	2,428,900	2,403,100	-1.06%
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**	2,492,300	2,451,700	-1.63%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	2,492,300	2,451,700	-1.63%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	2,492,300	2,451,700	-1.63%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	151	29	-80.79%
19	451	Miscellaneous Service Revenues	8	8	
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**	159	37	-76.73%
26		**Total Electric Operating Revenues**	2,492,459	2,451,737	-1.63%

Company Name: Black Hills Power, Inc.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,519,687	1,915,946	26.08%
6	501 Fuel	20,371,360	24,742,166	21.46%
7	502 Steam Expenses	5,185,786	4,650,460	-10.32%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	1,300,438	652,969	-49.79%
11	506 Miscellaneous Steam Power Expenses	1,663,077	936,998	-43.66%
12	507 Rents	2,945,410	2,423,614	-17.72%
13	509 Allowances		(82,622)	
14	TOTAL Operation - Steam	32,985,758	35,239,531	6.83%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	1,258,757	1,461,556	16.11%
18	511 Maintenance of Structures	650,399	948,205	45.79%
19	512 Maintenance of Boiler Plant	4,550,855	4,926,451	8.25%
20	513 Maintenance of Electric Plant	1,239,194	1,023,549	-17.40%
21	514 Maintenance of Miscellaneous Steam Plant	635,610	211,216	-66.77%
22				
23	TOTAL Maintenance - Steam	8,334,815	8,570,977	2.83%
24				
25	**TOTAL Steam Power Production Expenses**	41,320,573	43,810,508	6.03%
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**			

Company Name: Black Hills Power, Inc.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	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	105,007	205,861	96.05%
27	547 Fuel	2,252,409	1,924,593	-14.55%
28	548 Generation Expenses	446,704	403,587	-9.65%
29	549 Miscellaneous Other Power Gen. Expenses	85,196	92,223	8.25%
30	550 Rents	111,694	120,185	7.60%
31				
32	TOTAL Operation - Other	3,001,010	2,746,449	-8.48%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	119,603	192,468	60.92%
36	552 Maintenance of Structures	4,465	86,593	1839.37%
37	553 Maintenance of Generating & Electric Plant	2,358,970	2,198,192	-6.82%
38	554 Maintenance of Misc. Other Power Gen. Plant	39,243	207,566	428.92%
39				
40	TOTAL Maintenance - Other	2,522,281	2,684,819	6.44%
41				
42	**TOTAL Other Power Production Expenses**	5,523,291	5,431,268	-1.67%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	46,362,379	47,714,478	2.92%
46	556 System Control & Load Dispatching	536,914	1,110,265	106.79%
47	557 Other Expenses		1,488	100.00%
48				
49	TOTAL Other Power Supply Expenses	46,899,293	48,826,231	4.11%
50				
51	**TOTAL Power Production Expenses**	93,743,157	98,068,007	4.61%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title		Last Year	This Year	% Change
1	Transmission Expenses				
2	Operation				
3	560	Operation Supervision & Engineering	693,618	542,316	-21.81%
4	561	Load Dispatching	1,815,588	2,687,249	48.01%
5	562	Station Expenses	86,525	227,547	162.98%
6	563	Overhead Line Expenses	16,665	80,196	381.22%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	19,852,473	19,525,881	-1.65%
9	566	Miscellaneous Transmission Expenses	143,265	106,677	-25.54%
10	567	Rents			
11					
12	TOTAL Operation - Transmission		22,608,134	23,169,866	2.48%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	11		-100.00%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	95,670	143,948	50.46%
17	571	Maintenance of Overhead Lines	44,047	118,060	168.03%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21	TOTAL Maintenance - Transmission		139,728	262,008	87.51%
22					
23	**TOTAL Transmission Expenses**		22,747,862	23,431,874	3.01%
24					
25	Distribution Expenses				
26	Operation				
27	580	Operation Supervision & Engineering	893,239	815,014	-8.76%
28	581	Load Dispatching	199,809	307,026	53.66%
29	582	Station Expenses	465,326	500,872	7.64%
30	583	Overhead Line Expenses	625,105	433,117	-30.71%
31	584	Underground Line Expenses	276,605	346,871	25.40%
32	585	Street Lighting & Signal System Expenses	1,865	91	-95.12%
33	586	Meter Expenses	373,875	844,445	125.86%
34	587	Customer Installations Expenses	34,953	43,760	25.20%
35	588	Miscellaneous Distribution Expenses	787,223	325,002	-58.72%
36	589	Rents	22,500	19,854	-11.76%
37					
38	TOTAL Operation - Distribution		3,680,500	3,636,052	-1.21%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	25,017	22,868	-8.59%
41	591	Maintenance of Structures		1,067	100.00%
42	592	Maintenance of Station Equipment	203,193	299,493	47.39%
43	593	Maintenance of Overhead Lines	1,935,818	2,439,713	26.03%
44	594	Maintenance of Underground Lines	159,663	254,059	59.12%
45	595	Maintenance of Line Transformers	23,695	34,695	46.42%
46	596	Maintenance of Street Lighting, Signal Systems	140,614	168,448	19.79%
47	597	Maintenance of Meters	58,890	30,253	-48.63%
48	598	Maintenance of Miscellaneous Dist. Plant	135,696	25,977	-80.86%
49					
50	TOTAL Maintenance - Distribution		2,682,586	3,276,573	22.14%
51					
52	**TOTAL Distribution Expenses**		6,363,086	6,912,625	8.64%

Company Name: Black Hills Power, Inc.

SCHEDULE 10

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	24,271	47,693	96.50%
4	902 Meter Reading Expenses	787,795	218,944	-72.21%
5	903 Customer Records & Collection Expenses	2,188,415	1,622,659	-25.85%
6	904 Uncollectible Accounts Expenses	360,666	336,288	-6.76%
7	905 Miscellaneous Customer Accounts Expenses	573,843	833,857	45.31%
8				
9	TOTAL Customer Accounts Expenses	3,934,990	3,059,441	-22.25%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	219,781	348,586	58.61%
14	908 Customer Assistance Expenses	1,008,287	1,054,784	4.61%
15	909 Informational & Instructional Adv. Expenses	11,933	15,807	32.46%
16	910 Miscellaneous Customer Service & Info. Exp.	81,230	83,925	3.32%
17				
18	TOTAL Customer Service & Info Expenses	1,321,231	1,503,102	13.77%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses	506	934	84.58%
24	913 Advertising Expenses			
25	916 Miscellaneous Sales Expenses	250	-	-100.00%
26				
27	TOTAL Sales Expenses	756	934	23.54%
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	8,793,348	13,514,468	53.69%
32	921 Office Supplies & Expenses	4,105,478	3,663,973	-10.75%
33	922 (Less) Administrative Expenses Transferred - Cr.	(14,496)	(30,917)	-113.28%
34	923 Outside Services Employed	2,457,187	2,303,682	-6.25%
35	924 Property Insurance	904,602	849,740	-6.06%
36	925 Injuries & Damages	1,061,725	1,373,910	29.40%
37	926 Employee Pensions & Benefits	3,513,499	298,396	-91.51%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	826,060	873,235	5.71%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	266,833	218,333	-18.18%
42	930.2 Miscellaneous General Expenses	717,716	1,253,076	74.59%
43	931 Rents	385,017	488,245	26.81%
44				
45	TOTAL Operation - Admin. & General	23,016,969	24,806,141	7.77%
46	Maintenance			
47	935 Maintenance of General Plant	650,708	1,085,009	66.74%
48				
49	**TOTAL Administrative & General Expenses**	23,667,677	25,891,150	9.39%
50				
51	**TOTAL Operation & Maintenance Expenses**	151,778,759	158,867,133	4.67%

Company Name: Black Hills Power, Inc.

SCHEDULE 11

MONTANA TAXES OTHER THAN INCOME

Year: 2011

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	1,567	2,755	75.81%
5	Montana PSC	8,153	9,010	10.51%
6	Franchise Taxes			
7	Property Taxes	172,612	227,420	31.75%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	7,446	7,623	2.38%
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51	**TOTAL MT Taxes Other Than Income**	189,778	246,808	30.05%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2011

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

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2011

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

Company Name: Black Hills Power, Inc.

SCHEDULE 14

Pension Costs

Year: 2011

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	57,753,396	55,615,376	-3.70%
8	Service cost	797,599	1,214,408	52.26%
9	Interest Cost	3,092,519	3,280,041	6.06%
10	Plan participants' contributions		-	
11	Amendments	5,960,633	1,374,150	-76.95%
12	Actuarial Gain	852,020	(1,258,269)	-247.68%
13	Acquisition			
14	Benefits paid	(2,898,856)	(2,472,310)	14.71%
15	Benefit obligation at end of year	65,557,311	57,753,396	-11.90%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	48,227,903	39,039,528	-19.05%
18	Actual return on plan assets	65,651	5,361,041	8065.97%
19	Acquisition			
20	Employer contribution	(377,840)	6,299,644	1767.28%
21	Plan participants' contributions	-	-	
22	Benefits paid	(2,898,856)	(2,472,310)	14.71%
23	Fair value of plan assets at end of year	45,016,858	48,227,903	7.13%
24	**Funded Status**	(20,540,453)	(9,525,493)	53.63%
25	Unrecognized net actuarial loss	26,960,577	17,663,686	-34.48%
26	Unrecognized prior service cost	323,240	385,649	19.31%
27	Prepaid (accrued) benefit cost	6,743,364	8,523,842	26.40%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	5.50%	6.05%	10.00%
31	Expected return on plan assets	7.75%	8.00%	3.23%
32	Rate of compensation increase	3.70%	4.25%	14.86%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	797,599	1,271,224	59.38%
36	Interest cost	3,092,519	3,280,041	6.06%
37	Expected return on plan assets	(3,619,415)	(3,008,272)	16.89%
38	Amortization of prior service cost	62,409	62,159	-0.40%
39	Recognized net actuarial loss	1,486,044	1,377,517	-7.30%
40	Net periodic benefit cost	1,819,156	2,982,669	63.96%
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	1,215	1,247	2.63%
48	Not Covered by the Plan	56	52	-7.14%
49	Active	748	813	8.69%
50	Retired	213	190	-10.80%
51	Deferred Vested Terminated	198	192	-3.03%

Company Name: Black Hills Power, Inc.

SCHEDULE 15

Other Post Employment Benefits (OPEBS)

Year: 2011

	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	4.35%	5.00%	14.94%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	9.51%	10.00%	5.15%
10	Actuarial Cost Method			
11	Rate of compensation increase			
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	7,975,741	7,978,048	0.03%
20	Service cost	213,964	209,786	-1.95%
21	Interest Cost	342,710	365,143	6.55%
22	Plan participants' contributions	-	-	
23	Amendments			
24	Actuarial Gain	(138,585)	(151,115)	-9.04%
25	Acquisition			
26	Benefits paid	(260,130)	(426,121)	-63.81%
27	Benefit obligation at end of year	8,133,700	7,975,741	-1.94%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	(1,390,963)	(964,842)	30.63%
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution			
33	Plan participants' contributions	-	-	
34	Benefits paid	(260,130)	(426,121)	-63.81%
35	Fair value of plan assets at end of year	(1,651,093)	(1,390,963)	15.76%
36	**Funded Status**	(9,784,793)	(9,366,704)	4.27%
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost	(9,784,793)	(9,366,704)	4.27%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	213,964	209,786	-1.95%
42	Interest cost	342,710	365,143	6.55%
43	Expected return on plan assets	-	-	
44	Amortization of prior service cost			
45	Recognized net actuarial loss	(138,585)	(151,115)	-9.04%
46	Net periodic benefit cost	418,089	423,814	1.37%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			
49	Amount Funded through 401(h)			
50	Amount Funded through Other ___________			
51	TOTAL			
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ___________			
55	TOTAL			

Company Name: Black Hills Power, Inc.

Other Post Employment Benefits (OPEBS) Continued

Year: 2011

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	1,232	1,192	-3.25%
3	Not Covered by the Plan			
4	Active	995	992	-0.30%
5	Retired	129	107	-17.05%
6	Spouses/Dependants covered by the Plan	108	93	-13.89%
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: 2011

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: 2011

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, President and Chief Executive Officer						
2	Linden R. Evans President and Chief Operating Officer- Utilties						
3	Anthony S. Cleberg Executive Vice President and Chief Financial Officer						
4	Steven J. Helmers Senior Vice President and General Counsel						
5	Robert A. Myers Senior Vice President- Human Resources						

*PLEASE REFER TO ATTACHED SCHEDULE 17A - THE SUMMARY COMPENSATION TABLE FROM THE BHC ANNUAL MEETING OF SHAREHOLDERS AND PROXY STATEMENT.

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the years ended December 31, 2011, 2010 and 2009. We have no employment agreements with our Named Executive Officers.

Name and Principal Position	Year	Salary	Stock Awards[1]	Non-Equity Incentive Plan Compensation[2]	Change in Pension Value and Nonqualified Deferred Compensation Earnings[3]	All Other Compensation[4]	Total
David R. Emery Chairman, President and Chief Executive Officer	2011	$638,462	$741,037	$341,803	$1,263,510	$ 61,133	$3,045,945
	2010	$588,924	$605,554	$672,000	$ 766,046	$ 60,138	$2,692,662
	2009	$564,000	$674,723	$221,088	$ 361,799	$ 51,990	$1,873,600
Anthony S. Cleberg Executive Vice President and Chief Financial Officer	2011	$336,538	$324,175	$111,743	$ 9,640	$229,078	$1,011,174
	2010	$321,923	$288,372	$234,000	—	$149,607	$ 993,902
	2009	$315,000	$321,300	$ 79,380	$ 102,058	$198,778	$1,016,516
Linden R. Evans President and Chief Operating Officer – Utilities	2011	$383,077	$370,519	$153,812	$ 58,978	$223,235	$1,189,621
	2010	$333,538	$365,257	$288,000	—	$148,397	$1,135,192
	2009	$274,000	$406,978	$ 76,720	$ 102,553	$ 29,086	$ 889,337
Steven J. Helmers Sr. Vice President and General Counsel	2011	$291,538	$250,095	$ 77,563	$ 249,809	$ 96,448	$ 965,453
	2010	$276,923	$249,918	$179,200	$ 178,390	$ 74,271	$ 958,702
	2009	$270,000	$278,462	$ 76,720	$ 113,474	$ 26,231	$ 764,887
Robert A. Myers Sr. Vice President, Human Resources	2011	$292,000	$185,257	$ 77,563	—	$173,436	$ 728,256
	2010	$279,846	$168,199	$180,480	—	$125,821	$ 754,346
	2009	$261,322	$287,404	$ 61,600	$ 28,938	$101,990	$ 741,254

(1) Stock Awards represent the grant date fair value related to restricted stock, restricted stock units and performance shares that have been granted as a component of long-term incentive compensation. The grant date fair value is computed in accordance with the provisions of accounting standards for stock compensation. Assumptions used in the calculation of these amounts are included in Note 11 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2011. The amount included for performance shares is based on the level the award is expected to payout. If the award were based on the maximum payout level, the amounts for the Stock Awards column would be increased to the following amounts:

	2011	2010	2009
David R. Emery	$996,808	$823,477	$944,509
Anthony S. Cleberg	$436,067	$392,150	$449,766
Linden R. Evans	$498,404	$496,698	$569,717
Steven J. Helmers	$336,414	$339,854	$389,802
Robert A. Myers	$249,209	$228,727	$362,347

(2) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2011 awards at its January 25, 2012 meeting and the awards were paid on March 2, 2012.

(3) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective years.

The Pension Plan and PRB were frozen effective January 1, 2010 for participants who did not satisfy the age 45 and 10 years of service eligibility. Messrs. Cleberg, Evans and Helmers did not meet the eligibility choice criteria and their Defined Pension and PRB benefits were frozen. Mr. Myers did not meet the one year service requirement prior to the freeze date and therefore was never in the Pension Plan.

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"). Messrs. Emery and Helmers are participants in the Grandfathered PEP and 2005 PEP. Messrs. Cleberg, Evans and Myers were the only Named Executive Officers participating in the 2007 PEP. The 2007 PEP was eliminated effective January 1, 2010 and was replaced with employer contributions into a Nonqualified Deferred Compensation Plan ("NQDC"). The NQDC employer contributions are reported in the All Other Compensation column.

No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The value attributed to each Named Executive Officer from each plan is shown in the table below.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2011	$127,968	$627,383	$508,159	$1,263,510
	2010	$ 88,118	$369,162	$308,766	$ 766,046
	2009	$ 43,690	$167,024	$151,085	$ 361,799
Anthony S. Cleberg	2011	$ 6,644	$ 2,996	—	$ 9,640
	2010	$ 3,713	$ 2,660	$(52,506)	—
	2009	$ 36,790	$ 12,762	$ 52,506	$ 102,058
Linden R. Evans	2011	$ 33,608	$ 25,370	—	$ 58,978
	2010	$ 22,976	$ 19,195	$(163,783)	—
	2009	$ 25,375	$ 24,629	$ 52,549	$ 102,553
Steven J. Helmers	2011	$ 37,490	$ 22,071	$190,248	$ 249,809
	2010	$ 28,263	$ 18,239	$131,888	$ 178,390
	2009	$ 34,129	$ 18,295	$ 61,050	$ 113,474
Robert A. Myers	2011	—	—	—	—
	2010	—	—	$ (28,938)	—
	2009	—	—	$ 28,938	$ 28,938

(4) All Other Compensation includes amounts allocated under the 401(k) match, defined contributions, NQDC contributions, dividends received on restricted stock and other personal benefits. Mr. Cleberg's 2009 other personal benefits also include temporary living, travel and other relocation expenses, including an $89,050 loss on the sale of his home in 2009.

	Year	401(k) Match	Defined Contribution	NQDC Contribution	Dividends on Restricted Stock	Other Personal Benefits	Total Other Compensation
David R. Emery	2011	$14,700	—	—	$38,494	$ 7,939	$ 61,133
Anthony S. Cleberg	2011	$14,700	$7,350	$181,263	$18,370	$ 7,395	$229,078
Linden R. Evans	2011	$14,700	$7,350	$172,562	$21,225	$ 7,398	$223,235
Steven J. Helmers	2011	$14,700	$7,350	$ 54,062	$14,414	$ 5,922	$ 96,448
Robert A. Myers	2011	$14,700	$7,296	$129,144	$11,426	$10,870	$173,436

Company Name: Black Hills Power, Inc.

BALANCE SHEET

Year: 2011

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	751,226,307	963,042,216	-22%
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	177,978,541	25,126,903	608%
9	107 Construction Work in Progress - Electric	35,704,655	9,872,733	262%
10	108 (Less) Accumulated Depreciation	(324,433,412)	(341,035,323)	5%
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.	(2,937,117)	(3,034,523)	3%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	642,409,282	658,842,314	-2%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property	5,618	5,618	
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.	(3,956)	(3,956)	
20	123 Investments in Associated Companies			
21	123.1 Investments in Subsidiary Companies			
22	124 Other Investments	4,493,899	4,678,820	-4%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	4,495,561	4,680,482	-4%
25				
26	**Current & Accrued Assets**			
27	131 Cash	2,040,659	2,808,282	-27%
28	132-134 Special Deposits			
29	135 Working Funds	4,175	4,175	
30	136 Temporary Cash Investments			
31	141 Notes Receivable	17,448	31,132	-44%
32	142 Customer Accounts Receivable	16,011,944	14,932,925	7%
33	143 Other Accounts Receivable	7,296,436	2,089,236	249%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(230,060)	(143,461)	-60%
35	145 Notes Receivable - Associated Companies	39,955,209	50,602,589	-21%
36	146 Accounts Receivable - Associated Companies	6,891,040	6,997,613	-2%
37	151 Fuel Stock	7,135,764	6,864,962	4%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	13,589,713	14,076,589	-3%
41	155 Merchandise			
42	156 Other Material & Supplies	100	1,328	-92%
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed	533,690	1,131,352	-53%
45	165 Prepayments	3,617,542	3,089,753	17%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	7,580,915	8,364,400	-9%
49	174 Miscellaneous Current & Accrued Assets			
50	**TOTAL Current & Accrued Assets**	104,444,575	110,850,875	-6%

BALANCE SHEET

Year: 2011

	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	3,238,032	3,100,071	4%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
8a	182.3	Other Regulatory Assets	38,308,105	49,000,766	-22%
9	183	Prelim. Survey & Investigation Charges	328,007	540,159	-39%
10	184	Clearing Accounts	117,954	1,218,734	-90%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	(54,318)	84,277	-164%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	3,015,994	2,765,012	9%
16	190	Accumulated Deferred Income Taxes	26,398,567	50,772,793	-48%
17	**TOTAL Deferred Debits**		71,352,341	107,481,812	-34%
18					
19	**TOTAL Assets & Other Debits**		822,701,759	881,855,483	-7%

	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	247,687,972	274,785,027	-10%
35	217	(Less) Reacquired Capital Stock	(1,261,746)	(1,290,121)	2%
36	**TOTAL Proprietary Capital**		309,417,551	336,486,231	-8%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	255,000,000	255,000,000	
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies			
43	224	Other Long Term Debt	21,622,173	21,541,577	0%
44	225	Unamortized Premium on Long Term Debt			
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(119,370)	(115,230)	-4%
46	**TOTAL Long Term Debt**		276,502,803	276,426,347	0%

BALANCE SHEET

Year: 2011

	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	986,005	840,546	17%
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	3,748	3,009	25%
12		**TOTAL Other Noncurrent Liabilities**	989,753	843,555	17%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	13,521,848	11,908,739	14%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	12,558,267	18,598,082	-32%
20	235	Customer Deposits	977,967	1,067,410	-8%
21	236	Taxes Accrued	3,973,829	4,429,546	-10%
22	237	Interest Accrued	4,126,079	4,118,805	0%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	1,264,725	650,967	94%
27	242	Miscellaneous Current & Accrued Liabilities	4,863,936	5,101,316	-5%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	41,286,651	45,874,865	-10%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	3,434,637	1,460,557	135%
34	253	Other Deferred Credits	38,611,351	35,509,803	9%
34a	254	Other Regulatory Liabilities	14,774,843	17,123,183	-14%
35	255	Accumulated Deferred Investment Tax Credits	14,266		100%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	137,669,904	168,130,942	-18%
39		**TOTAL Deferred Credits**	194,505,001	222,224,485	-12%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		822,701,759	881,855,483	-7%

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/18/2012	End of 2011/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS
December 31, 2011, 2010 and 2009

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (the Company, "we," "us" or "our") is an electric utility serving customers in South Dakota, Wyoming and Montana. We are 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 our ownership interests in the assets, liabilities and expenses of our jointly owned facilities (Note 4).

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. Actual results could differ from those estimates.

Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Regulatory Accounting

Our 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.

Our regulated utility operations follow accounting standards for regulated operations and our financial statements reflect the effects of the different rate making principles followed by the various jurisdictions regulating our electric operations. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply to our regulated operations. In the event we determine that we no longer meet the criteria for following accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations in an amount that could be material.

Regulatory assets are included in Regulatory assets, current and Regulatory assets, non-current on the accompanying Balance Sheets. Regulatory liabilities are included in Regulatory liabilities, current and Regulatory liabilities, non-current on the accompanying Balance Sheets.

Our regulatory assets and liabilities for which we recover the costs, but we do not earn a return were as follows as of December 31 (in thousands):

	Maximum Recovery Period	2011	2010
Regulatory assets:			
Unamortized loss on reacquired debt	14 years	$ 2,765	$ 3,016
AFUDC	45 years	8,552	9,489
Employee benefit plans	13 years	27,602	18,049
Deferred energy costs	1 year	6,605	3,584
Flow through accounting	35 years	5,789	4,772
Other		452	2,414
Total regulatory assets		$ 51,765	$ 41,324
Regulatory liabilities:			
Cost of removal for utility plant	53 years	$ 23,347	$ 15,429
Employee benefit plans	13 years	15,282	10,204
Other		1,845	4,575
Total regulatory liabilities		$ 40,474	$ 30,208

Regulatory assets represent items we expect to recover from customers through probable future rates.

Unamortized Loss on Reacquired Debt - The early redemption premium on reacquired bonds is being amortized over the remaining term of the original bonds.

AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset itself is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity, and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income.

Deferred Energy Costs - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers in excess of current rates and which will be recovered in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission.

Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. This regulatory treatment was applied to the tax benefit generated by repair costs that were previously capitalized for tax purposes in a rate case settlement that was reached with respect to Black Hills Power in 2010. In this instance, the agreed upon rate increase was less than it would have been absent the flow-through treatment. A regulatory asset established to reflect the future increases in income taxes payable will be recovered from customers as the temporary differences reverse.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Cost of Removal - Cost of removal for utility plant represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal obligation for removal. Liabilities will be settled and trued up following completion of the related activities.

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirements. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement aspect of a rate regulated environment.

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.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable consist of sales to residential, commercial, industrial, municipal and other customers all of which do not bear interest. These accounts receivables are stated at billed and unbilled amounts net of write-offs or payment received.

We maintain an allowance for doubtful accounts which reflects our best estimate of potentially uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect the ability to pay.

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollected. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including unbilled revenue. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collection success given the existing collections environment.

Following is a summary of accounts receivable at December 31 (in thousands):

	2011	2010
Accounts receivable trade	$ 16,447	$ 21,365
Unbilled revenues	8,364	7,581
Total accounts receivable - customers	24,811	28,946
Allowance for doubtful accounts	(143)	(230)
Net accounts receivable	$ 24,668	$ 28,716

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.

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are generally stated on a weighted-average cost basis.

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 are computed on a straight-line basis using an annual composite rate of 2.2% in 2011, 2.2% in 2010 and 2.8% in 2009.

Derivatives and Hedging Activities

From time to time we utilize risk management contracts including forward purchases and sales to hedge the price of fuel for our combustion turbines and fixed-for-float swaps to fix the interest on any variable rate debt. Contracts that qualify as derivatives under accounting standards for derivatives, 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. Accounting standards for derivatives require that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Accounting standards for derivatives allow hedge accounting for qualifying fair value and cash flow hedges. 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 should be recognized currently in earnings in the same accounting period. Conversely, the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument should be reported as a component of other comprehensive income and be reclassified into earnings or as a regulatory asset or regulatory liability, net of tax, 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.

Fair Value Measurements

Accounting standards for fair value measurements provide a single definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and also requires disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

Level 1 - Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities.

Level 2 - Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources.

Impairment of Long-Lived Assets

We periodically evaluate whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of our long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, we 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, we would recognize an impairment loss.

Income Taxes

We use 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. We classify deferred tax assets and liabilities into current and non-current amounts based on the classification of the related assets and liabilities.

We file 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.

It is our policy to apply the flow-through method of accounting for investment tax credits. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. Another acceptable accounting method and an exception to this general policy currently in our regulated businesses is to apply the deferral method whereby the credit is amortized as a reduction of income tax expense over the useful lives of the related property which gave rise to the credits.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Other Comprehensive Income, ASU 2011-05 and ASU 2011-12

FASB issued an accounting standards update amending ASC 220 to improve the comparability, consistency and transparency of reporting of comprehensive income. It amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial statements. ASU No. 2011-05 requires retrospective application, and it is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. In December 2011, FASB issued ASU 2011-12. ASU 2011-12 indefinitely deferred the provisions of ASU 2011-05 requiring the presentation of reclassification adjustments for items reclassified from other comprehensive income to net income be presented on the face of the financial statements.

We have elected to early adopt the provisions of ASU 2011-05 as amended by ASU 2011-12. The adoption changed the presentation of certain financial statements and provided additional details in notes to the financial statements, but did not have any other impact on our financial statements. See the accompanying Comprehensive Income Statement and additional disclosures in Note 8.

Fair Value Measurements and Disclosures, ASC 820

The ASC for Fair Value Measurements and Disclosures defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosure requirements related to fair value measurements. This does not expand the application of fair value accounting to any new circumstances, but applies the framework to other applicable GAAP that requires or permits fair value measurement. We apply fair value measurements to certain assets and liabilities, primarily employee benefit plan assets and other miscellaneous financial instruments.

In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements, disclosure of inputs and techniques used in valuation and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements are required to be presented separately. These disclosures are required for interim and annual reporting periods and were effective for us January 1, 2010, except the disclosures related to purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective January 1, 2011. The guidance requires additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 9.

Recently Issued Accounting Standards and Legislation

Fair Value Measurement, ASU 2011-04

FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between GAAP and IFRS. This amendment changes the wording used to describe fair value and requires additional disclosures. We do not expect this amendment, which is effective for interim and annual periods beginning after December 31, 2011, to have an impact on our financial position, results of operations, or cash flows.

(3) PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2011	December 31, 2011 Weighted Average Useful Life (in years)	December 31, 2010	December 31, 2010 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Electric plant:						
Production	$ 504,088	51	$ 475,762	50	45	65
Transmission	115,063	47	116,056	43	40	60
Distribution	289,833	39	271,470	37	16	45
Plant acquisition adjustment	4,870	32	4,870	32	32	32
General	72,045	21	58,777	22	8	45
Construction work in progress	9,873		35,705			
Total electric plant	995,772		962,640			
Less accumulated depreciation and amortization	(313,581)		(304,800)			
Electric plant net of accumulated depreciation and amortization	$ 682,191		$ 657,840			

(4) JOINTLY OWNED FACILITIES

We use the proportionate consolidation method to account for our percentage interest in the assets, liabilities and expenses of the following facilities:

- We own a 20% interest in the Wyodak Plant (the "Plant"), a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. We receive our proportionate share of the Plant's capacity and are committed to pay our share of its additions, replacements and operating and maintenance expenses.

- We own a 35% interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us 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. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

- We own a 52% interest in the Wygen III power plant. MDU and the City of Gillette each owns an undivided ownership interest in the Wygen III generation facility and are obligated to make payments for costs associated with administrative services and proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations.

The investments in our jointly owned plants and accumulated depreciation are included in the corresponding captions in the accompanying Balance Sheets. Our share of direct expenses of the Plant is included in the corresponding categories of operating expenses in the accompanying Statements of Income.

As of December 31, 2011, our interests in jointly-owned generating facilities and transmission systems included on our Balance Sheets were as follows (dollars in thousands):

Interest in jointly-owned facilities	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 109,007	$ 718	$ 46,104
Transmission Tie	$ 19,648	$ —	$ 4,061
Wygen III	$ 129,791	$ 249	$ 5,328

(5) LONG-TERM DEBT

Long-term debt outstanding was as follows (in thousands):

	Maturity Date	Fixed Interest Rate	December 31, 2011	December 31, 2010
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.125%	180,000	180,000
Unamortized discount, First Mortgage Bonds due 2039			(115)	(119)
Pollution control revenue bonds due 2014	October 1, 2014	4.80%	6,450	6,450
Pollution control revenue bonds due 2024	October 1, 2024	5.35%	12,200	12,200
Series 94A Debt	June 1, 2024	3.00%	2,855	2,855
Other	May 12, 2012	13.66%	37	117
Total long-term debt			276,427	276,503
Less current maturities			(37)	(81)
Net long-term debt			$ 276,390	$ 276,422

Deferred finance costs of approximately $3.1 million were capitalized and are being amortized over the term of the debt. Amortization of deferred financing costs is included in Interest expense.

Substantially all of our property is subject to the lien of the indenture securing our first mortgage bonds. First mortgage bonds may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. We were in compliance with our debt covenants at December 31, 2011.

Series AC Bonds

In February 2010, the Series 8.06% AC bonds matured. These were paid in full for $30.0 million of principal plus accrued interest of $1.2 million.

Series Y Bonds

In March 2010, we completed redemption of our Series Y 9.49% bonds in full. The bonds were originally due in 2018. A total of \$2.7 million was paid on March 31, 2010, which includes the principal balance of \$2.5 million plus accrued interest and an early redemption premium of 2.618%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Balance Sheet and is being amortized over the remaining term of the original bonds.

Series Z Bonds

In June 2010, we completed redemption of our Series Z 9.35% bonds in full. The bonds were originally due in 2021. A total of \$21.8 million was paid on June 1, 2010, which included the principal balance of \$20.0 million plus accrued interest and an early redemption premium of 4.675%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Balance Sheet and is being amortized over the remaining term of the original bonds.

Long-term Debt Maturities

Scheduled maturities of our outstanding long-term debt (excluding unamortized discounts) are as follows (in thousands):

2012	$	37
2013	$	—
2014	$	6,450
2015	$	—
2016	$	—
Thereafter	$	270,055

(6) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments were as follows (in thousands):

	December 31, 2011 Carrying Value	December 31, 2011 Fair Value	December 31, 2010 Carrying Value	December 31, 2010 Fair Value
Cash and cash equivalents	$ 2,812	$ 2,812	$ 2,045	$ 2,045
Long-term debt, including current maturities	$ 276,427	$ 362,055	$ 276,503	$ 301,964

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

Cash and Cash Equivalents

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

Long-Term Debt

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

(7) INCOME TAXES

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

	December 31, 2011	December 31, 2010	December 31, 2009
Current	$ 14,921	$ (14,885)	$ (3,296)
Deferred	(2,931)	25,626	11,600
Total income tax expense	$ 11,990	$ 10,741	$ 8,304

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

	December 31, 2011	December 31, 2010
Deferred tax assets, current:		
Asset valuation reserve	$ 491	$ 217
Employee benefits	1,086	803
Rate refund	360	428
Total deferred tax assets, current	1,937	1,448
Deferred tax liabilities, current:		
Prepaid expenses	(256)	(251)
Deferred costs	(2,529)	(2,056)
Total deferred tax liabilities, current	(2,785)	(2,307)
Net deferred tax assets (liabilities), current	$ (848)	$ (859)
Deferred tax assets, non-current:		
Plant related differences	$ —	$ 909
Regulatory liabilities	14,644	10,074
Employee benefits	3,922	3,547
Net operating loss	28,072	9,147
Items of other comprehensive income	263	225
Research and development credit	780	1,613
Other	1,155	—
Total deferred tax assets, non-current	48,836	25,515
Deferred tax liabilities, non-current:		
Accelerated depreciation and other plant related differences	(148,254)	(132,338)
AFUDC	(5,559)	(6,168)
Regulatory assets	(5,019)	(5,557)
Employee benefits	(2,356)	(2,983)
Other	(968)	(788)
Total deferred tax liabilities, non-current	(162,156)	(147,834)
Net deferred tax assets (liabilities), non-current	$ (113,320)	$ (122,319)
Net deferred tax assets (liabilities)	$ (114,168)	$ (123,178)

The following table reconciles the change in the net deferred income tax assets (liabilities) from December 31, 2010 to December 31, 2011 and from December 31, 2009 to December 31, 2010 to deferred income tax expense (benefit) (in thousands):

	2011	2010
Change in deferred income tax assets (liabilities)	$ (9,010)	$ 25,118
Deferred taxes related to regulatory assets and liabilities	4,968	9,272
Deferred taxes associated with other comprehensive income	15	(2,141)
Deferred taxes related to property basis differences	156	(4,713)
Deferred taxes related to AFUDC	937	(1,910)
Other	3	—
Deferred income tax expense (benefit) for the period	$ (2,931)	$ 25,626

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

	December 31, 2011	December 31, 2010	December 31, 2009
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.4)	(0.6)	(0.9)
Equity AFUDC	(0.6)	(2.0)	(6.2)
Flow through adjustments *	(3.4)	(7.4)	—
Other	0.1	0.6	(1.5)
	30.7%	25.6%	26.4%

* The flow-through adjustments relate primarily to an accounting method change for tax purposes that was filed with the 2008 tax return and for which consent was received from the IRS in September 2009. The effect of the change allows us to take a current tax deduction for repair costs that were previously capitalized for tax purposes. These costs will continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit that was attributable to the 2008 through 2010 tax years. For years prior to 2008, we did not record a regulatory asset for the repairs deduction as the tax benefit was not flowed through to customers.

The accounting standards for uncertain tax positions clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with accounting standards for income taxes. The accounting standards prescribe a recognition threshold and measurement attributes for the financial statement recognition and measurement of a tax position taken or expected to be taken. The impact of this implementation had no effect on our financial statements.

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

	2011	2010
Unrecognized tax benefits at January 1	$ 3,094	$ 3,877
Additions for prior year tax positions	795	130
Reductions for prior year tax positions	(294)	(913)
Unrecognized tax benefits at December 31	$ 3,595	$ 3,094

The reduction for prior year tax positions relate to the reversal through otherwise allowed tax depreciation. The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.4 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the year ended December 31, 2011 and 2010, the interest expense recognized related to income tax matters was not material to our financial results.

The Company files income tax returns in the United States federal jurisdiction as a member of the BHC consolidated group. 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, 2012.

At December 31, 2011, we have federal NOL carry forward of $80.2 million, of which $54.6 million will expire in 2030 and $25.6 million will expire in 2031. Ultimate usage of this NOL depends upon our future taxable income.

(8) COMPREHENSIVE INCOME

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

	December 31, 2011		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustment - net gain (loss)	$ (108)	$ 38	$ (70)
Reclassification adjustments of cash flow hedges settled and included in net income	65	(23)	42
Net change in fair value of derivatives designated as cash flow hedges	—	—	—
Other comprehensive income (loss)	$ (43)	$ 15	$ (28)

	December 31, 2010		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustment - net gain (loss)	$ (145)	$ 51	$ (94)
Reclassification adjustments of cash flow hedges settled and included in net income	64	(23)	41
Net change in fair value of derivatives designated as cash flow hedges	6	(2)	4
Other comprehensive income (loss)	$ (75)	$ 26	$ (49)

	December 31, 2009		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustment - net gain (loss)	$ 150	$ (52)	$ 98
Reclassification adjustments of cash flow hedges settled and included in net income	64	(24)	40
Net change in fair value of derivatives designated as cash flow hedges	(5)	3	(2)
Other comprehensive income (loss)	$ 209	$ (73)	$ 136

During 2002, we entered into a treasury lock to hedge a portion of a first mortgage bond. The treasury lock cash settled on the bond pricing date, and resulted in a $1.8 million loss. This treasury lock was treated as a cash flow hedge and accordingly the resulting loss is carried in Accumulated other comprehensive loss on the accompanying Balance Sheet and amortized over the life of the related bonds as additional interest expense.

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

	December 31, 2011	December 31, 2010
Derivatives designated as cash flow hedges	$ (801)	$ (843)
Employee benefit plans	(489)	(419)
Total accumulated other comprehensive loss	$ (1,290)	$ (1,262)

(9) EMPLOYEE BENEFIT PLANS

Funded Status of Benefit Plans

The funded status of postretirement benefit plan is required to be recognized in the statement of financial position. The funded status for pension plan 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. The measurement date of the plans is December 31, our year-end balance sheet date.

We apply accounting standards for regulated operations, and accordingly, the unrecognized net periodic benefit cost that would have been reclassified to Accumulated other comprehensive income (loss) was alternatively recorded as a regulatory asset or regulatory liability, net of tax.

Defined Benefit Pension Plan

We have a noncontributory defined benefit pension plan ("Pension Plan") covering employees 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. Our funding policy is in accordance with the federal government's funding requirements. The Pension Plan's assets are held in trust and consist primarily of equity and fixed income investments. We use a December 31 measurement date for the Pension Plan.

As of January 1, 2012, the Pension Plan has been frozen to new employees and certain employees who did not meet age and service based criteria at the time the Plans were frozen. The benefits for the plans are based on years of service and calculations of average earnings during a specific time period prior to retirement. In July 2009, the Board of Directors approved a partial freeze to the Pension Plan for all participants with the exception of bargaining unit participants. The freeze eliminated new non-bargaining unit employees from participation in the Pension Plan and froze the benefits of current non-bargaining unit participants except certain eligible employees who met age and service based criteria. In September of 2010, our bargaining unit employees voted to freeze participation in the Pension Plan and to freeze the benefits of current bargaining unit participants except for certain eligible employees who met age and service based criteria. An additional age and points-based employer contribution under the Company's 401(k) retirement savings plan was established.

The Pension 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 Pension Plan portfolio. The expected long-term rate of return for each asset class is determined primarily from adjusted long-term historical returns for the asset class. It is anticipated that long-term future returns will not achieve historical results. The expected long-term rate of return for equity investments was 8.75% and 9.25% for the 2011 and 2010 plan years, respectively.

Pension Plan Assets

Percentage of fair value of Pension Plan assets at December 31:

	2011	2010
Equity	69%	68%
Fixed income	28%	29%
Cash	3%	3%
Total	100%	100%

The Investment Policy for the Pension Plans is to seek to achieve the following long-term objectives: 1) a rate of return in excess of the annualized inflation rate based on a five-year moving average; 2) a rate of return that meets or exceeds the assumed actuarial rate of return as stated in the Plan's actuarial report; 3) a rate of return on investments, net of expenses, that is equal to or exceeds various benchmark rates on a moving three-year average, and 4) maintenance of sufficient income and liquidity to pay monthly retirement benefits. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Pension Plan may invest, including prohibitions on short sales.

Supplemental Non-qualified Defined Benefit Retirement Plans

We have various supplemental retirement plans ("Supplemental Plans") for key executives. The Supplemental Plans are non-qualified defined benefit plans. We use a December 31 measurement date for the Supplemental Plans. Effective January 1, 2010, we eliminated a non-qualified pension plan in which some of our officers participated due to the partial freeze of our qualified pension plan. We also amended the NQDC, which was adopted in 1999. The NQDC is a non-qualified deferred compensation plan that provides executives with an opportunity to elect to defer compensation and receive benefits without reference to the limitations on contributions in the Plan or those imposed by the IRS. The amended NQDC provides for non-elective non-qualified restoration benefits to certain officers who are not eligible to continue accruing benefits under the Defined Benefit Pension Plans and associated non-qualified pension restoration plans. All contributions to the non-qualified plans are subject to a graded vesting schedule of 20% per year over five years with vesting credit beginning with service in the Plan on and after January 1, 2010.

Supplemental Plan Assets

The Supplemental Plans have no assets. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in our Non-Pension Postretirement Healthcare Plan ("Healthcare Plan") and who retire on or after attaining age 55 after completing at least five years of service are entitled to postretirement healthcare benefits. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. We may amend or change the Healthcare Plan periodically. We are not pre-funding our retiree medical plan. We use a December 31 measurement date for the Healthcare Plan. The Board of Directors approved an amendment to the Healthcare Plan which changed the structure of the Healthcare Plan for non-union employees to a RMSA structure which was effective January 1, 2010. In September 2010, the bargaining unit employees voted to change the structure of their benefits to an RMSA. This change was effective January 1, 2011. It has been determined that the Healthcare Plan's post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy.

Plan Assets

The Healthcare Plan has no assets. We fund on a cash basis as benefits are paid.

Plan Contributions and Estimated Cash Flows

Contributions made to the Supplemental Non-qualified Defined Benefit Retirement Plans and the Non-pension Defined Benefit Postretirement Plan are expected to be made in the form of benefit payments. Contributions to each of the plans were as follows (in thousands):

	2011	2010
Defined Benefit Plans		
Defined Benefit Pension Plan	$ —	$ 8,798
Non-pension Defined Benefit Postretirement Healthcare Plan	$ 428	$ 657
Supplemental Non-qualified Defined Benefit Plan	$ 130	$ 108
Defined Contribution Plans		
Company Retirement Contribution	$ 371	$ 171
Matching Contributions	$ 1,296	$ 1,029

Contributions to our employee benefit plans to be made in 2012 are as follows (in thousands):

	2012
Defined Benefit Plans	
Defined Benefit Pension Plan	$ —
Non-pension Defined Benefit Postretirement Healthcare Plan	$ 658
Supplemental Non-qualified Defined Benefit Plan	$ 154

Fair Value Measurements

As required by accounting standards for fair value measurements, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect their placement within the fair value hierarchy levels. The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis as of December 31 (in thousands):

Defined Benefit Pension Plan	December 31, 2011			
	Level 1	Level 2	Level 3	Total Fair Value
Money market fund	$ 40	$ —	$ —	$ 40
Registered investment companies - equity	12,743	—	—	12,743
Registered investment companies - fixed income	12,603	—	—	12,603
Common collective trust	—	16,143	—	16,143
Insurance contracts	—	1,288	—	1,288
Structured products	—	2,200	—	2,200
Total investments measured at fair value	$ 25,386	$ 19,631	$ —	$ 45,017

Defined Benefit Pension Plan

	December 31, 2010			
	Level 1	Level 2	Level 3	Total Fair Value
Registered investment companies - equity	$ 15,090	$ —	$ —	$ 15,090
Registered investment companies - fixed income	12,952	—	—	12,952
Common collective trust	—	19,104	—	19,104
Insurance contracts	—	1,082	—	1,082
Total investments measured at fair value	$ 28,042	$ 20,186	$ —	$ 48,228

Registered Investment Companies: Investments are valued at the closing price reported on the active market on which the individual securities are traded.

Common Collective Trust: The Pension Plan owns units of the Common Collective Trust funds that they are utilizing in their portfolio. The value of each unit of any fund as of any valuation date shall be determined by calculating the total value of such fund's assets as of the close of business on such valuation date, deducting its total liabilities as of such time and date, and then dividing the so-determined net asset value of such fund by the total number of units of such fund outstanding the date of valuation.

Insurance Contract: These investments are valued on a cash basis on any given valuation date.

Structured Products: Investments are linked by derivatives to observable financial indexes and valued through present value models.

Plan Reconciliations

The following tables provide a reconciliation of the Employee Benefit Plan's obligations and fair value of assets, components of the net periodic expense and elements of regulatory assets and liabilities and AOCI (in thousands):

Benefit Obligations

	Defined Benefit Pension		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 57,753	$ 55,615	$ 2,152	$ 1,690	$ 7,517	$ 9,432
Service cost	798	1,215	—	—	210	340
Interest cost	3,092	3,280	114	100	365	547
Actuarial loss (gain)	852	4,129	(30)	54	(308)	(88)
Amendments	—	260	—	—	—	(2,270)
Change in participant assumptions	—	—	—	—	171	—
Discount rate change	6,668	—	186	—	433	—
Benefits paid	(2,899)	(2,472)	(130)	(109)	(707)	(658)
Asset transfer (to) from affiliate	(707)	(3,300)	—	417	(40)	(328)
Plan curtailment reduction	—	(974)	—	—	—	—
Medicare Part D adjustment	—	—	—	—	67	88
Plan participants' contributions	—	—	—	—	499	454
Net increase (decrease)	7,804	2,138	140	462	690	(1,915)
Projected benefit obligation at end of year	$ 65,557	$ 57,753	$ 2,292	$ 2,152	$ 8,207	$ 7,517

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

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Beginning market value of plan assets	$ 48,228	$ 39,040	$ —	$ —	$ —	$ —
Investment income	66	5,361	—	—	—	—
Benefits paid	(2,899)	(2,472)	—	—	—	—
Employer contributions	—	8,798	—	—	—	—
Asset transfer to affiliate	(378)	(2,499)	—	—	—	—
Ending market value of plan assets	$ 45,017	$ 48,228	$ —	$ —	$ —	$ —

Amounts recognized in the Balance Sheets consist of (in thousands):

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Regulatory asset (liability)	$ 27,284	$ 18,049	$ —	$ —	$ (590)	$ (1,050)
Current (liability)	$ —	$ —	$ (154)	$ (141)	$ (658)	$ (428)
Non-current (liability)	$ (20,540)	$ (9,525)	$ (3,060)	$ (2,011)	$ (7,497)	$ (7,096)

Accumulated Benefit Obligation

	Defined Benefit		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Accumulated benefit obligation	$ 59,823	$ 52,250	$ 2,292	$ 2,058	$ 8,207	$ 7,517

Components of Net Periodic Expense

	Defined Benefit Pension			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Service cost	$ 798	$ 1,214	$ 1,155	$ —	$ —	$ —	$ 210	$ 340	$ 216
Interest cost	3,093	3,280	3,143	114	100	100	365	547	444
Expected return on assets	(3,619)	(3,008)	(2,780)	—	—	—	—	—	—
Amortization of prior service cost	62	62	87	—	—	—	(314)	(141)	—
Amortization of transition obligation	—	—	—	—	—	—	—	171	51
Amortization of loss (gain)	—	—	—	—	—	—	—	—	—
Recognized net actuarial loss (gain)	1,486	1,378	1,586	48	30	43	163	—	—
Curtailment expense	—	57	189	—	—	—	—	—	—
Net periodic expense	$ 1,820	$ 2,983	$ 3,380	$ 162	$ 130	$ 143	$ 424	$ 917	$ 711

Accumulated Other Comprehensive Income (Loss)

Amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2011	2010	2011	2010	2011	2010
Net loss	$ —	$ —	$ (489)	$ (418)	$ —	$ —
Prior service cost	—	—	—	—	—	—
Transition obligation	—	—	—	—	—	—
	$ —	$ —	$ (489)	$ (418)	$ —	$ —

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 2012 were as follows (in thousands):

	Defined Benefits	Supplemental Non-qualified Defined Benefit Retirement Plans	Non-pension Defined
Net loss	$ 1,689	$ 36	$ 90
Prior service cost	37	—	(181)
Transition obligation	—	—	—
Total net periodic benefit cost expected to be recognized during calendar year 2011	$ 1,726	$ 36	$ (90)

Assumptions

	Defined Benefit Pension			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Weighted-average assumptions used to determine benefit obligations:									
Discount rate	4.65%	5.50%	6.05%	4.70%	5.50%	6.10%	4.35%	5.00%	5.90%
Rate of increase in compensation levels	3.67%	3.70%	4.25%	N/A	5.00%	5.00%	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:									
Discount rate	5.50%	6.05%	6.25%	5.00%	6.10%	6.20%	5.00%	5.90%	6.10%
Expected long-term rate of return on assets*	7.75%	8.00%	8.50%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	3.70%	4.25%	4.25%	N/A	5.00%	5.00%	N/A	N/A	N/A

* The expected rate of return on plan assets changed to 7.25% for the calculation of the 2012 net periodic pension cost.

The healthcare benefit obligation was determined at December 31, 2011, using an initial healthcare trend rate of 9.01% grading down to an ultimate rate of 4.5% in 2028, and at December 31, 2010, using an initial healthcare trend rate of 9.51% trending down to an ultimate rate of 4.5% in 2027.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1% increase or 1% decrease in the healthcare cost trend assumptions would affect the service and interest costs and the accumulated periodic postretirement benefit obligation as follows (dollars in thousands):

Change in Assumed Trend Rate	Service and Interest Costs	Accumulated Periodic Postretirement Benefit Obligation
1% increase	$ 22	$ 422
1% decrease	$ (19)	$ (372)

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

	Defined Benefit Pension	Supplemental Non-qualified Defined Benefit Retirement Plans	Non-pension Defined
2012	$ 3,159	$ 154	$ 658
2013	$ 3,223	$ 113	$ 702
2014	$ 3,258	$ 113	$ 652
2015	$ 3,323	$ 113	$ 635
2016	$ 3,338	$ 84	$ 639
2017-2021	$ 19,035	$ 684	$ 3,886

Defined Contribution Plan

The Parent sponsors a 401(k) retirement savings plan in which employees may participate. Participants may elect to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis, up to a maximum amount established by the Internal Revenue Service. The plan provides for company matching contributions and company retirement contributions. Employer contributions vest at 20% per year and are fully vested when the participant has 5 years of service.

(10) RELATED-PARTY TRANSACTIONS

Receivables and Payables

We have accounts receivable and accounts payable balances related to transactions with other BHC subsidiaries. These balances as of December 31, were as follows (in thousands):

	2011	2010
Related party accounts receivable	$ 6,998	$ 6,891
Related party accounts payable	$ 18,598	$ 12,562

Money Pool Notes Receivable and Notes Payable

We have a Utility Money Pool Agreement with the Parent, Cheyenne Light and Black Hills Utility Holdings. Under the agreement, we may borrow from the Parent. The Agreement restricts us from loaning funds to the Parent or to any of the Parent's non-utility subsidiaries; the Agreement does not restrict us 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 1%.

Advances under this note bear interest at 2.75% above the daily LIBOR rate (3.05% at December 31, 2011). We had the following balances with the Utility Money Pool as of and for the years ended December 31 (in thousands):

	2011	2010	2009
Notes receivable (payable) with Utility Money Pool, net	$ 50,477	$ 39,862	$ 57,737
Net interest income (expense)	$ 1,414	$ 467	$ (1,123)

Other Balances and Transactions

We had the following related party transactions for the years ended December 31, 2011 and 2010 included in the corresponding captions in the accompanying Statements of Income:

- We received revenues from Black Hills Wyoming, Inc. for electricity.
- We received revenues from Cheyenne Light for the sale of electricity and dispatch services.
- We recorded revenues relating to payments received pursuant to a natural gas swap entered into with Enserco.
- We purchase coal from WRDC. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.
- We purchase excess power generated by Cheyenne Light.
- In order to fuel our combustion turbine, we purchase natural gas from Enserco. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.
- In addition, we also pay the Parent and Black Hills Utility Holdings for allocated corporate support service costs incurred on our behalf.
- We have two contracts with Cheyenne Light under which Cheyenne Light sells up to 40 MW of wind-generated, renewable energy to us. These amounts are included in Fuel and purchased power on the accompanying Statements of Income.

	2011	2010	2009
	(in thousands)		
Revenues:			
Black Hills Wyoming for electricity	$ 9	$ 574	$ 873
Cheyenne Light for electricity and dispatch services	$ 957	$ 1,200	$ 1,823
Purchases:			
Coal purchases from WRDC	$ 21,319	$ 13,569	$ 16,284
Excess power purchased from Cheyenne Light	$ 9,363	$ 8,664	$ 8,580
Natural gas from Enserco*	$ 647	$ 1,652	$ 2,250
Corporate support services from Parent and Black Hills Utility Holdings	$ 18,567	$ 17,145	$ 15,014
Renewable wind energy from Cheyenne Light	$ 5,236	$ 4,538	$ 2,791

* BHC sold Enserco on February 29, 2012.

We have funds on deposit from Black Hills Wyoming for transmission system reserve which are included in Other, non-current liabilities on the accompanying Balance Sheets. We have transmission system reserve balances as follows as of December 31 (in thousands):

	2011	2010
Transmission Deposit	$ 2,110	$ 2,044

Interest on the transmission system reserve deposit accrues quarterly at an average prime rate (3.25% at December 31, 2011). We paid interest for the years ended December 31 as follows (in thousands):

	2011	2010	2009
Interest expense on transmission deposit	$ 67	$ 65	$ 70

(11) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2011	2010	2009
	(in thousands)		
Non-cash investing activities -			
Property, plant and equipment financed with accrued liabilities	$ 1,882	$ 7,188	$ 10,191
Money pool activity - net repayment of funds loaned	$ —	$ —	$ 25,000
Non-cash financing activities -			
Money pool activity - net repayment of funds borrowed	$ —	$ —	$ (25,000)
Supplemental disclosure of cash flow information:			
Cash (paid) refunded during the period for -			
Interest (net of amounts capitalized)	$ (16,294)	$ (19,554)	$ (14,252)
Income taxes	$ (15,347)	$ 15,805	$ 3,700

(12) COMMITMENTS AND CONTINGENCIES

Partial Sale of Wygen III

On April 9, 2009, we sold to MDU a 25% ownership interest in our Wygen III generation facility. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility. Proceeds of $32.8 million were received of which $30.2 million was used to pay down a portion of Parent debt. MDU continued to reimburse us for its 25% of the total costs paid to complete the project. The Wygen III generation facility began commercial operations on April 1, 2010. In conjunction with the sales transaction, we also modified a 2004 PPA between us and MDU.

On July 14, 2010, we sold a 23% ownership interest in Wygen III to the City of Gillette for $62.0 million. The purchase terminates the current PPA with the City of Gillette, and the Wygen III Participation Agreement has been amended to include the City of Gillette. The Participation Agreement provides that the City of Gillette will pay us for administrative services and share in the costs of operating the plant for the life of the facility. The estimated amount of net fixed assets sold totaled $55.8 million. We recognized a gain on the sale of $6.2 million.

Power Purchase and Transmission Services Agreements

We have the following power purchase and transmission agreements as of December 31, 2011:

- A PPA with PacifiCorp expiring on December 31, 2023, which provides for the purchase by us of 50 MW of electric capacity and energy. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal fired electric generating plants;
- A firm point-to-point transmission access agreement to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the western region through December 31, 2023;
- Cheyenne Light entered into a PPA with Happy Jack. Under a separate inter-company agreement expiring on September 3, 2028, Cheyenne Light has agreed to sell up to 15 MW of the facility output from Happy Jack to us;
- Cheyenne Light entered into a PPA with Silver Sage. Under a separate inter-company agreement expiring on September 30, 2029, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to us; and
- A Generation Dispatch Agreement with Cheyenne Light that requires us to purchase all of Cheyenne Light's excess energy.

Costs incurred under these agreements were as follows for the years ended December 31 (in thousands):

Contract	Contract Type		2011		2010		2009
PacifiCorp	Electric capacity and energy	$	12,515	$	12,936	$	11,862
PacifiCorp	Transmission access	$	1,215	$	1,215	$	1,215
Cheyenne Light	Happy Jack Wind Farm	$	1,955	$	2,815	$	2,078
Cheyenne Light	Silver Sage Wind Farm	$	3,281	$	1,723	$	713

The following is a schedule of future minimum payments required under the power purchase, transmission services, coal and gas supply agreements (in thousands):

2012	$	11,895
2013	$	11,895
2014	$	11,895
2015	$	11,895
2016	$	11,895
Thereafter	$	49,091

Long-Term Power Sales Agreements

We have the following power sales agreements as of December 31, 2011:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU;

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette their operating component of spinning reserves;

- An agreement under which we supply energy and capacity to MEAN expiring on May 31, 2023. This contract is unit-contingent based on up to 10 MW from our Neil Simpson II and up to 10 MW from our Wygen III plants. The capacity purchase requirements decrease over the term of the agreement.

- A PPA with MEAN, expiring on April 1, 2015. Under this contract, MEAN purchases 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

Legal Proceedings

We are 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 our financial position, results of operations or cash flows.

(13) QUARTERLY HISTORICAL DATA (Unaudited)

We operate on a calendar year basis. The following table sets forth selected unaudited historical operating results data for each quarter (in thousands):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2011				
Operating revenues	$ 59,194	$ 56,098	$ 64,940	$ 65,399
Operating income	$ 11,917	$ 9,181	$ 19,175	$ 14,447
Net income	$ 5,881	$ 3,741	$ 10,510	$ 6,965
2010				
Operating revenues	$ 54,489	$ 56,438	$ 59,051	$ 59,785
Operating income	$ 9,361	$ 10,510	$ 21,092	$ 14,305
Net income	$ 5,934	$ 4,102	$ 14,078	$ 7,154

Company Name: Black Hills Power, Inc.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	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: 2011

	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	0%
35	361	Structures & Improvements	5,970	5,970	0%
36	362	Station Equipment	445,583	445,583	0%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	413,196	414,300	0%
39	365	Overhead Conductors & Devices	438,481	435,426	1%
40	366	Underground Conduit	909	909	0%
41	367	Underground Conductors & Devices	15,834	15,414	3%
42	368	Line Transformers	48,686	56,058	-13%
43	369	Services	6,344	6,344	
44	370	Meters	434	489	-11%
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	1,401,740	1,406,797	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2011

	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	2,935		100%
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment	15,157	15,157	
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	18,092	15,157	
17				
18	**TOTAL Electric Plant in Service**	1,419,832	1,421,954	

MONTANA DEPRECIATION SUMMARY

Year: 2011

	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	1,406,797	926,971	953,401	
8	General	15,157	11,230	10,969	
9	**TOTAL**	1,421,954	938,201	964,370	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

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

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	83.4.25			
2	Order Number	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		54.90%		
13	Preferred Stock				
14	Long Term Debt		45.10%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2011

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	31,267,992	27,097,056	15%
6	Depreciation	22,029,623	27,217,003	-19%
7	Amortization	(6,541,711)		-100%
8	Deferred Income Taxes - Net	25,625,579	(2,917,246)	978%
9	Investment Tax Credit Adjustments - Net		(14,266)	100%
10	Change in Operating Receivables - Net	(14,542,283)	4,758,335	-406%
11	Change in Materials, Supplies & Inventories - Net		(901,563)	100%
12	Change in Operating Payables & Accrued Liabilities - Net	(5,523,373)	989,089	-658%
13	Allowance for Funds Used During Construction (AFUDC)	(2,748,351)	(704,602)	-290%
14	Change in Other Assets & Liabilities - Net	1,035,009	(6,430,168)	116%
15	Other Operating Activities (explained on attached page)		2,340,533	-100%
16	**Net Cash Provided by/(Used in) Operating Activities**	50,602,485	51,434,171	-2%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(78,601,707)	(40,909,013)	-92%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	62,000,000	1,135,000	5363%
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates	17,875,221	(10,615,166)	268%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	2,202,407	(196,773)	1219%
27	**Net Cash Provided by/(Used in) Investing Activities**	3,475,921	(50,585,952)	107%
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	(52,566,198)	(80,596)	-65122%
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 on attached page)	(1,176,314)		-100%
46	**Net Cash Provided by (Used in) Financing Activities**	(53,742,512)	(80,596)	-66581%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	335,894	767,623	-56%
49	**Cash and Cash Equivalents at Beginning of Year**	1,708,940	2,044,834	-16%
50	**Cash and Cash Equivalents at End of Year**	2,044,834	2,812,457	-27%

Attachment 23A
Footnotes for Statement of Cash Flow

Line 14, last year- Change in other assets & liabilities includes:

$ 3,882,771	Decrease in other regulatory assets
$ 3,562,000	Increase in other regulatory liabilities
$(8,798,000)	Contribution to defined benefit plan
$ 2,388,238	Other changes in assets and liabilities
$ 1,035,009	**Total**

Line 14, current year- Change in other assets & liabilities includes:

$ (915,729)	Changes in other current and long-term assets
$(2,339,055)	Changes in other current and long-current liabilities
$(1,210,916)	Increase in other regulatory assets
$(1,964,468)	Decrease in other regulatory liabilities
$(6,430,168)	**Total**

Line 15, current year- Other operating activities includes:

$2,404,931	Employee benefit plan expense
$ 245,153	Adjustments to regulatory activity
$ 457,416	Amortization of deferred finance costs
$ (766,967)	Gain on sale of assets
$2,340,533	**Total**

Line 26, last year- Other investing activities includes:

$ (198,593)	Increase in cash surrender value of PEP insurance
$ 2,401,000	Amounts received for jointly owned power plant construction
$ 2,202,407	**Total**

Line 26, this year- Other investing activities includes:

$ (196,773) Increase in cash surrender value for PEP insurance

Line 45, last year- Other financing activities includes:

$ (1,176,314) Payment for deferred financing costs

LONG TERM DEBT

Year: 2011

	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 AE	08/2002	08/2032	75,000,000	74,343,750	75,000,000	7.23%	5,422,500	7.23%
2									
3	Series AF	10/2009	11/2039	180,000,000	177,722,527	180,000,000	6.125%	11,025,000	6.13%
4									
5	2004 Pollution Control:								
6	Campbell Cty 4.8%	11/2004	10/2014	1,550,000	1,532,563	1,550,000	4.80%	74,400	4.80%
7	Campbell Cty 5.35%	11/2004	10/2024	12,200,000	12,062,750	12,200,000	5.35%	652,700	5.35%
8	Pennington Cty 4.8%	11/2004	10/2014	2,050,000	2,026,938	2,050,000	4.80%	98,400	4.80%
9	Weston Cty 4.8%	11/2004	10/2014	2,850,000	2,817,938	2,850,000	4.80%	136,800	4.80%
10									
11	1994 A Environ Improv								
12	Bond	06/1994	06/2024	3,000,000	2,930,057	2,855,000	4.82%	124,369	4.36%
13									
14	Bear Paw Energy	06/2000	05/2012	1,078,000	1,078,000	36,577	13.66%	11,108	30.37%
15									
16									
17									
18									
19	Line 11, the 1994 A Bond has a variable interest rate. The weighted average rate for 2011 was 4.82%.								
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			277,728,000	274,514,523	276,541,577		17,545,277	6.34%

PREFERRED STOCK

Year: 2011

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	N/A									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2011

		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: 2011

	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	2% 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: 2011

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,422
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	(964)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	458
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	2,452
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	2,452
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	2,452
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	20
37		Industrial	2
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	35
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	88,000
45		Average Annual Residential Cost per (Kwh) (Cents) *	8.13
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	515
48		Gross Plant per Customer	13.09

MONTANA CUSTOMER INFORMATION

Year: 2011

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

Company Name: Black Hills Power, Inc.

SCHEDULE 30

MONTANA EMPLOYEE COUNTS

Year: 2011

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

Company Name: Black Hills Power, Inc.

SCHEDULE 31

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

Year: 2012

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

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2011

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	31	1900	408	297,917	120,863
2	Feb.	1	1000	391	246,892	84,762
3	Mar.	7	1900	353	262,031	99,700
4	Apr.	14	1100	290	283,880	127,439
5	May	12	1300	291	227,892	79,134
6	Jun.	29	1600	394	280,855	131,728
7	Jul.	19	1600	452	278,297	89,006
8	Aug.	1	1500	420	311,239	128,120
9	Sep.	1	1700	329	288,212	143,943
10	Oct.	4	1600	313	296,870	146,129
11	Nov.	19	1800	337	327,524	166,289
12	Dec.	5	1800	357	342,656	156,537
13	**TOTAL**				3,444,265	`

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	1,717,008	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,714,485
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	15,221	for Resale	102,418
7	(Less) Energy for Pumping			
8	**NET Generation**	1,732,229	Non-Requirements Sales	
9	Purchases	1,720,640	for Resale	1,473,650
10	Power Exchanges			
11	Received	34,342	Energy Furnished	
12	Delivered	(42,946)	Without Charge	
13	**NET Exchanges**	(8,604)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	7,432,604	Electric Utility	138,367
16	Delivered	(7,432,604)		
17	**NET Transmission Wheeling**	-	Total Energy Losses	15,345
18	Transmission by Others Losses			
19	**TOTAL**	3,444,265	**TOTAL**	3,444,265

SOURCES OF ELECTRIC SUPPLY

Year: 2011

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	(199)
2					
3	Thermal	Ben French	Rapid City, SD	10	1,974
4					
5	Thermal	Ben French	Rapid City, SD	24	131,432
6					
7	Thermal	Osage	Osage, WY	35	-
8					
9	Thermal	Wyodak	Gillette, WY	69	370,633
10					
11	Thermal	Neil Simpson I	Gillette, WY	20	144,258
12					
13	Thermal	Neil Simpson II	Gillette, WY	84	646,325
14					
15	Thermal	Lange	Rapid City, SD	39	3,900
16					
17	Thermal	Neil Simpson CT 1	Gillette, WY	39	9,952
18					
19	Thermal	Wygen III	Gillette, WY	52	424,560
20					
21	Purchases	See Schedule 32			1,720,640
22					
23	Wheeling	See Schedule 32			-
24					
25	Total Interchange	See Schedule 32			(8,604)
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**			470	3,444,870

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2011

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**						

Company Name: Schedule 35a

Electric Universal System Benefits Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	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: 2011

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$6,700	$7,600	82	94	13	13
2	Commercial - Small	41,900	55,800	414	595	20	21
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	2,403,100	2,428,900	50,324	48,953	2	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**	$2,451,700	$2,492,300	50,820	49,642	35	36