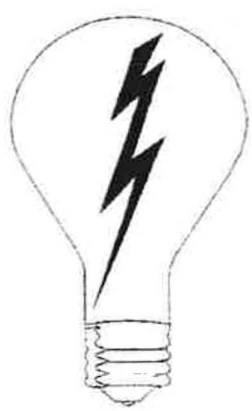
YEAR ENDING 2013

ANNUAL REPORT
OF

BLACK HILLS POWER, INC.

ELECTRIC UTILITY



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

REVISED - 2005

Electric Annual Report

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Description	Schedule

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Description	Schedule

IDENTIFICATION

Year: 2013

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:	1102 E. First Street Papillion, NE 68046
5.	Person Responsible for This Report:	Steven M. Jurek Vice President, Regulatory Services
5a.	Telephone Number:	402-221-2262
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	Jack W. Eugster	Excelsior, MN	$ 83,000.00
3	Michael H. Madison	Shrevport, LA	$ 70,000.00
4	Steven R. Mills	Monticello, IL	$ 70,000.00
5	Stephen D. Newlin	Westlake, OH	$ 81,000.00
6	Gary L. Pechota	Bethlehem, PA	$ 77,500.00
7	Rebecca B. Roberts	The Woodlands, TX	$ 75,000.00
8	Warren L. Robinson	Rapid City, SD	$ 80,000.00
9	John B. Vering	Southlake, TX	$ 60,000.00
10	Thomas J. Zeller	Rapid City, SD	$ 90,000.00
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14	(a) Mr. Emery is an officer of the company and thus receives no compensation for his		
15	services as a director.		
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Officers

Year: 2013

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 - Chief Human Resources Officer		Robert A. Myers
7	Vice President - Governance and Corporate Secretary		Roxann R. Basham
8	Vice President - Corporate Affairs		Stephen L. Pella
9	Vice President - Supply Chain		Perry S. Krush
10	Vice President - Strategic Planning and Development		Jeffrey B. Berzina (a)
11	Vice President - Regulatory Affairs		KyleD. White
12	Vice President - Corporate Controller		Richard W. Kinzley (b)
13	Vice President - Utility Operations		Stuart A. Wevik
14	Vice President - Operations Services		Ivan Vancas
15	Vice President and General Manager - Power Delivery		Mark L. Lux
16	Vice President and General Manager - Gillette Cmplex		Gregory L. Hager (c)
17	Vice President - Customer Service		Randy D. Winkelman
18	Vice President - BHP Operations		Vance Crocker (d)
19	Vice President - Energy Asset Optimization		Richard C. Loomis (e)
20	Vice President - Treasurer		Brian G. Iverson
21	Vice President - Regulatory Services and Resource Planning		Wendy M. Moser
22	Vice President - Regulatory Services		Steven M. Jurek
23	Vice President - Chief RiskOfficer		Garner M. Anderson (f)
24			
25	(a) Jeffrey B. Berzina's position changed from Vice President - Corporate Controller to Vice President -		
26	Strategic Planning and Development in March 2013		
27			
28	(b) Richard W. Kinzley's position changed from Vice President - Strategic Planning and Development to		
29	Vice President - Corporate Controller in March 2013		
30			
31	(c) Gregory L. Hager's position of Vice President and General Manager - Gillette Complex was eliminated		
32	upon his retirement in October 2013		
33			
34	(d) Vance Crocker was appointed Vice President - BHP Operations in July 2013		
36			
37	(e) Richard C. Loomis' position changed from Vice President - BHP Operations to Vice President - Energy		
38	Asset Management in July 2013		
39			
40	(f) Garner M. Anderson's position of Vice President - Chief Risk Officer was eliminated as an officer		
41	position in January 2013		
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CORPORATE STRUCTURE

Year: 2013

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	30,172,736	100.00%
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50	**TOTAL**		30,172,736	

CORPORATE ALLOCATIONS

Year: 2013

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

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2013

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Wyodak Resources Development Corp.	Coal Sales to Utility	Fair Market Value (based on similar arms-length transactions)	15,522,578	26.03%	406,692
2	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	8,832,581	7.60%	231,414
3	Black Hills Service Company	Information Technology, General Accounting, Insurance, Regulatory and Governmental Sevices, Facilities, Various Other Non-Power Goods and Services	Black Hills Service Company Cost Allocation Manual	23,663,354	47.97%	619,980
4	Black Hills Utility Holding Company	Various Non-power Goods and Services	Black Hills Utility Holdings Company Cost Allocation Manual	11,583,592	45.62%	303,490
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32	**TOTAL**			59,602,105		1,561,576

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2013

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	1,010,157	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point open Access Transmission Tariff	1,008,914	100.00%	
3	Cheyenne Light Fuel and Power	Transmission Service	Point to Point Open Access Transmission Tariff Fair Market Value	1,506,150	1.93%	39,461
4	Black Hills Wyoming	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	2,461	100.00%	
5	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	1,338,427	1.72%	35,067
6	Black Hills Colorado Electric	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	1,177,983	0.85%	30,863
7	Cheyenne Light Fuel and Power	Neil Simpson Complex	Fair Market Value (based on similar arms-length transactions	4,282,163	5.50%	112,193
8	Cheyenne Light Fuel and Power	Environmental Complex	Fair Market Value (based on similar arms-length transactions	1,158,872	1.49%	30,362
9	Cheyenne Light Fuel and Power	Generation Dispatch	Fair Market Value (based on similar arms-length transactions	792,011	1.02%	20,751
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32	**TOTAL**			12,277,138		268,697

MONTANA UTILITY INCOME STATEMENT

Year: 2013

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	242,566,363	253,500,080	4.51%
2					
3		Operating Expenses			
4	401	Operation Expenses	139,611,215	142,312,904	1.94%
5	402	Maintenance Expense	13,000,384	15,077,965	15.98%
6	403	Depreciation Expense	27,523,255	28,027,555	1.83%
7	404-405	Amortization of Electric Plant			
8	406	Amort. of Plant Acquisition Adjustments	97,406	97,406	
9	407	Amort. of Property Losses, Unrecovered Plant	(240,333)		-100.00%
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	5,042,502	5,740,691	13.85%
12	409.1	Income Taxes - Federal	(10,453,480)	(255,317)	97.56%
13		- Other	50	3,054	6008.00%
14	410.1	Provision for Deferred Income Taxes	38,653,618	42,103,609	8.93%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(14,026,110)	(28,654,691)	-104.30%
16	411.4	Investment Tax Credit Adjustments			
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**	**199,208,507**	**204,453,176**	**2.63%**
21		**NET UTILITY OPERATING INCOME**	**43,357,856**	**49,046,904**	**13.12%**

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	5,200	4,690	-9.81%
3	442	Commercial & Industrial - Small	114,300	28,341	-75.20%
4		Commercial & Industrial - Large	2,464,700	3,104,392	25.95%
5	444	Public Street & Highway Lighting			
6	445	Other Sales to Public Authorities			
7	446	Sales to Railroads & Railways			
8	448	Interdepartmental Sales			
9					
10		**TOTAL Sales to Ultimate Consumers**	**2,584,200**	**3,137,423**	**21.41%**
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	**2,584,200**	**3,137,423**	**21.41%**
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	**2,584,200**	**3,137,423**	**21.41%**
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	12	16	33.33%
19	451	Miscellaneous Service Revenues	38	22	-42.11%
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**	**50**	**38**	**-24.00%**
26		**Total Electric Operating Revenues**	**2,584,250**	**3,137,461**	**21.41%**

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2013

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,708,807	1,717,567	0.51%
6	501 Fuel	23,457,498	20,115,827	-14.25%
7	502 Steam Expenses	3,896,433	3,321,972	-14.74%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	1,189,410	893,269	-24.90%
11	506 Miscellaneous Steam Power Expenses	871,600	921,530	5.73%
12	507 Rents	2,578,736	2,438,297	-5.45%
13	509 Allowance	30		-100.00%
14	TOTAL Operation - Steam	33,702,514	29,408,462	-12.74%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	1,832,408	1,422,184	-22.39%
18	511 Maintenance of Structures	746,430	794,511	6.44%
19	512 Maintenance of Boiler Plant	3,324,262	4,486,596	34.97%
20	513 Maintenance of Electric Plant	991,324	904,984	-8.71%
21	514 Maintenance of Miscellaneous Steam Plant	181,304	148,611	-18.03%
22				
23	TOTAL Maintenance - Steam	7,075,728	7,756,886	9.63%
24				
25	**TOTAL Steam Power Production Expenses**	40,778,242	37,165,348	-8.86%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2013

	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	186,035	254,289	36.69%
27	547	Fuel	2,699,433	2,818,871	4.42%
28	548	Generation Expenses	463,821	543,124	17.10%
29	549	Miscellaneous Other Power Gen. Expenses	96,935	96,202	-0.76%
30	550	Rents	180,173	178,905	-0.70%
31					
32		TOTAL Operation - Other	3,626,397	3,891,391	7.31%
33					
34	Maintenance				
35	551	Maintenance Supervision & Engineering	172,533	152,798	-11.44%
36	552	Maintenance of Structures	16,605	6,637	-60.03%
37	553	Maintenance of Generating & Electric Plant	852,169	760,963	-10.70%
38	554	Maintenance of Misc. Other Power Gen. Plant	90,164	101,965	13.09%
39					
40		TOTAL Maintenance - Other	1,131,471	1,022,363	-9.64%
41					
42		**TOTAL Other Power Production Expenses**	4,757,868	4,913,754	3.28%
43					
44	Other Power Supply Expenses				
45	555	Purchased Power	42,550,316	47,501,867	11.64%
46	556	System Control & Load Dispatching	1,376,637	1,463,941	6.34%
47	557	Other Expenses	2,000		-100.00%
48					
49		TOTAL Other Power Supply Expenses	43,928,953	48,965,808	11.47%
50					
51		**TOTAL Power Production Expenses**	89,465,063	91,044,910	1.77%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2013

	Account Number & Title		Last Year	This Year	% Change
1	Transmission Expenses				
2	Operation				
3	560	Operation Supervision & Engineering	615,608	676,741	9.93%
4	561	Load Dispatching	2,417,158	2,132,512	-11.78%
5	562	Station Expenses	311,118	251,026	-19.31%
6	563	Overhead Line Expenses	34,291	88,663	158.56%
7	564	Underground Line Expenses		(143)	-100.00%
8	565	Transmission of Electricity by Others	19,246,947	19,431,175	0.96%
9	566	Miscellaneous Transmission Expenses	102,570	144,509	40.89%
10	567	Rents			
11					
12	TOTAL Operation - Transmission		22,727,692	22,724,483	-0.01%
13	Maintenance				
14	568	Maintenance Supervision & Engineering		27	100.00%
15	569	Maintenance of Structures			
16	570	Maintenance of Station Equipment	130,128	154,881	19.02%
17	571	Maintenance of Overhead Lines	57,584	82,137	42.64%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant	1,108		-100.00%
20					
21	TOTAL Maintenance - Transmission		188,820	237,045	25.54%
22					
23	**TOTAL Transmission Expenses**		22,916,512	22,961,528	0.20%
24					
25	Distribution Expenses				
26	Operation				
27	580	Operation Supervision & Engineering	1,146,108	1,344,942	17.35%
28	581	Load Dispatching	295,844	329,755	11.46%
29	582	Station Expenses	459,496	484,355	5.41%
30	583	Overhead Line Expenses	603,185	331,646	-45.02%
31	584	Underground Line Expenses	319,295	285,007	-10.74%
32	585	Street Lighting & Signal System Expenses	214	259	21.03%
33	586	Meter Expenses	907,761	730,645	-19.51%
34	587	Customer Installations Expenses	16,109	21,143	31.25%
35	588	Miscellaneous Distribution Expenses	308,586	602,634	95.29%
36	589	Rents	19,060	17,283	-9.32%
37					
38	TOTAL Operation - Distribution		4,075,658	4,147,669	1.77%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	1,680	567	-66.25%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	342,475	315,690	-7.82%
43	593	Maintenance of Overhead Lines	2,668,541	3,700,032	38.65%
44	594	Maintenance of Underground Lines	200,213	268,896	34.30%
45	595	Maintenance of Line Transformers	39,745	48,551	22.16%
46	596	Maintenance of Street Lighting, Signal Systems	103,250	51,125	-50.48%
47	597	Maintenance of Meters	98,505	70,790	-28.14%
48	598	Maintenance of Miscellaneous Dist. Plant	23,239	298,203	1183.20%
49					
50	TOTAL Maintenance - Distribution		3,477,648	4,753,854	36.70%
51					
52	**TOTAL Distribution Expenses**		7,553,306	8,901,523	17.85%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2013

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	39,588	56,653	43.11%
4	902 Meter Reading Expenses	34,496	17,032	-50.63%
5	903 Customer Records & Collection Expenses	1,508,851	1,724,651	14.30%
6	904 Uncollectible Accounts Expenses	255,021	455,148	78.47%
7	905 Miscellaneous Customer Accounts Expenses	721,235	597,007	-17.22%
8				
9	TOTAL Customer Accounts Expenses	2,559,191	2,850,491	11.38%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	234,184	168,647	-27.99%
14	908 Customer Assistance Expenses	1,247,275	1,093,855	-12.30%
15	909 Informational & Instructional Adv. Expenses	11,442	15,785	37.96%
16	910 Miscellaneous Customer Service & Info. Exp.	63,503	59,231	-6.73%
17				
18	TOTAL Customer Service & Info Expenses	1,556,404	1,337,518	-14.06%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision		534	100.00%
23	912 Demonstrating & Selling Expenses	3,436	38,188	1011.41%
24	913 Advertising Expenses		46	100.00%
25	916 Miscellaneous Sales Expenses	1,777		-100.00%
26				
27	TOTAL Sales Expenses	5,213	38,768	643.68%
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	16,400,545	16,917,795	3.15%
32	921 Office Supplies & Expenses	3,074,022	3,533,883	14.96%
33	922 (Less) Administrative Expenses Transferred - Cr.	(43,075)	(43,653)	-1.34%
34	923 Outside Services Employed	2,697,663	3,030,074	12.32%
35	924 Property Insurance	846,767	779,654	-7.93%
36	925 Injuries & Damages	2,392,564	1,912,375	-20.07%
37	926 Employee Pensions & Benefits	(148,360)	130,360	187.87%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	633,390	593,077	-6.36%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	228,351	270,072	18.27%
42	930.2 Miscellaneous General Expenses	770,596	1,267,405	64.47%
43	931 Rents	576,731	557,273	-3.37%
44				
45	TOTAL Operation - Admin. & General	27,429,194	28,948,315	5.54%
46	Maintenance			
47	935 Maintenance of General Plant	1,126,716	1,307,816	16.07%
48				
49	**TOTAL Administrative & General Expenses**	28,555,910	30,256,131	5.95%
50				
51	**TOTAL Operation & Maintenance Expenses**	152,611,599	157,390,869	3.13%

MONTANA TAXES OTHER THAN INCOME

Year: 2013

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	2,744	2,542	-7.36%
5	Montana PSC	5,383	8,856	64.52%
6	Franchise Taxes			
7	Property Taxes	142,219	136,706	-3.88%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	7,300	7,158	-1.95%
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51	**TOTAL MT Taxes Other Than Income**	157,646	155,262	-1.51%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES Year: 2013

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts to Montana are not significant.				
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43					
44					
45					
46					
47					
48					
49					
50	**TOTAL Payments for Services**				

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2013

	Description	Total Company	Montana	% Montana
1	Steve Daines for Montana	1,000	1,000	
2				
3				
4				
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47				
48				
49				
50	**TOTAL Contributions**	1000	1000	

Pension Costs

Year: 2013

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: $2,299,0000	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	69,820,705	65,557,311	-6.11%	
8	Service cost	852,492	765,087	-10.25%	
9	Interest Cost	2,969,417	2,968,853	-0.02%	
10	Plan participants' contributions	-	-		*
11	Amendments	-	-	-100.00%	
12	Actuarial Gain	(8,569,539)	3,379,272	139.43%	*
13	Acquisition	-	-		
14	Benefits paid	(4,849,811)	(2,849,818)	41.24%	
15	Benefit obligation at end of year	60,223,264	69,820,705	15.94%	
16	**Change in Plan Assets**				
17	Fair value of plan assets at beginning of year	53,464,694	45,016,858	-15.80%	
18	Actual return on plan assets	5,490,944	4,462,654	-18.73%	*
19	Acquisition	-	-		
20	Employer contribution	2,299,000	6,835,000	197.30%	
21	Plan participants' contributions	-	-		*
22	Benefits paid	(4,849,811)	(2,849,818)	41.24%	
23	Fair value of plan assets at end of year	56,404,827	53,464,694	-5.21%	
24	**Funded Status**	(3,818,437)	(16,356,011)	-328.34%	
25	Unrecognized net actuarial loss	13,512,258	26,417,526	95.51%	*
26	Unrecognized prior service cost	223,149	265,777	19.10%	*
27	Prepaid (accrued) benefit cost	9,916,970	10,327,292	4.14%	
28					
29	**Weighted-average Assumptions as of Year End**				
30	Discount rate	5.10%	4.35%	-14.71%	
31	Expected return on plan assets	6.75%	7.25%	7.41%	
32	Rate of compensation increase	3.91%	3.91%		
33					
34	**Components of Net Periodic Benefit Costs**				
35	Service cost	852,492	765,087	-10.25%	
36	Interest cost	2,969,417	2,968,853	-0.02%	
37	Expected return on plan assets	(3,764,001)	(3,139,674)	16.59%	
38	Amortization of prior service cost	42,628	57,463	34.80%	
39	Recognized net actuarial loss	2,608,786	2,599,343	-0.36%	
40	Net periodic benefit cost	2,709,322	3,251,072	20.00%	
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	571	579	1.40%	*
48	Not Covered by the Plan	-	-	-100.00%	
49	Active	244	255	4.51%	*
50	Retired	204	203	-0.49%	*
51	Deferred Vested Terminated	123	121	-1.63%	*

* A review by the BHC Treasury department identified corrections to what was reported for 2012.

Other Post Employment Benefits (OPEBS)

Year: 2013

	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	4.45%	3.65%	-17.98%	
8	Expected return on plan assets				
9	Medical Cost Inflation Rate	6.88%	7.13%	3.63%	*
10	Actuarial Cost Method				
11	Rate of compensation increase	4.00%	4.00%		
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**				
13					
14					
15	**Describe any Changes to the Benefit Plan:**				
16					
17	**TOTAL COMPANY**				
18	**Change in Benefit Obligation**				
19	Benefit obligation at beginning of year	6,765,664	8,207,382	21.31%	
20	Service cost	216,273	213,964	-1.07%	
21	Interest Cost	239,025	342,710	43.38%	
22	Plan participants' contributions	467,888	487,911	4.28%	*
23	Amendments	(341,572)		100.00%	
24	Actuarial Gain	(451,853)	(1,651,294)	-265.45%	*
25	Acquisition	-	-		
26	Benefits paid	(1,045,518)	(835,009)	20.13%	
27	Benefit obligation at end of year	5,849,907	6,765,664	15.65%	
28	**Change in Plan Assets**				
29	Fair value of plan assets at beginning of year			100.00%	
30	Actual return on plan assets				
31	Acquisition				
32	Employer contribution	577,630	347,098	-39.91%	
33	Plan participants' contributions	467,888	487,911	4.28%	
34	Benefits paid	(1,045,518)	(835,009)	20.13%	
35	Fair value of plan assets at end of year	-	-	100.00%	
36	**Funded Status**	(5,849,907)	(6,765,664)	-15.65%	
37	Unrecognized net actuarial loss	248,671	791,891	218.45%	*
38	Unrecognized prior service cost	(3,029,257)	(2,965,549)	2.10%	*
39	Prepaid (accrued) benefit cost	(8,630,493)	(8,939,322)	-3.58%	
40	**Components of Net Periodic Benefit Costs**				
41	Service cost	216,273	213,964	-1.07%	
42	Interest cost	239,025	342,710	43.38%	
43	Expected return on plan assets	-	-		
44	Amortization of prior service cost	(277,864)	(277,864)		
45	Recognized net actuarial loss	9,095	139,279	1431.38%	
46	Net periodic benefit cost	186,529	418,089	124.14%	
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	-	-		

* A review by the BHC Treasury department identified corrections to what was reported for 2012.

Other Post Employment Benefits (OPEBS) Continued

Year: 2013

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	444	448	0.90% *
3	Not Covered by the Plan			
4	Active	271	279	2.95% *
5	Retired	85	83	-2.35% *
6	Spouses/Dependants covered by the Plan	88	86	-2.27% *
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			

* A review by the BHC Treasury department identified corrections to what was reported for 2012.

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							

SCHEDULE 17

Year: 2013

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, 2013, 2012 and 2011. We have no employment agreements with our Named Executive Officers.

Name and Principal Position	Year	Salary(1)	Stock Awards(2)	Non-Equity Incentive Plan Compensation(3)	Changes in Pension Value and Nonqualified Deferred Compensation Earnings (4)	All Other Compensation(5)	Total
David R. Emery	2013	$689,650	$1,037,511	$996,155	$—	$64,294	$2,787,610
Chairman, President and Chief Executive	2012	$696,000	$865,325	$994,042	$713,494	$61,484	$3,330,345
Officer	2011	$638,462	$741,037	$341,803	$1,263,510	$61,133	$3,045,945
Anthony S. Cleberg	2013	$361,188	$399,050	$289,848	$—	$231,882	$1,281,968
Executive Vice President and Chief	2012	$364,385	$395,577	$325,343	$6,213	$170,984	$1,262,502
Financial Officer	2011	$336,538	$324,175	$111,743	$9,640	$229,078	$1,011,174
Linden R. Evans	2013	$428,481	$399,050	$446,992	$—	$308,013	$1,582,536
President and Chief Operating Officer –	2012	$429,231	$745,571	$501,800	$37,910	$209,319	$1,923,831
Utilities	2011	$383,077	$370,519	$153,812	$58,978	$223,235	$1,189,621
Steven J. Helmers	2013	$316,300	$269,349	$228,444	$—	$112,303	$926,396
Sr. Vice President –	2012	$318,461	$267,016	$256,414	$138,731	$85,824	$1,066,446
General Counsel	2011	$291,538	$250,095	$77,563	$249,809	$96,448	$965,453
Robert A. Myers	2013	$312,219	$219,468	$200,442	$—	$192,092	$924,221
Sr. Vice President –	2012	$315,230	$217,543	$224,983	$—	$144,391	$902,147
Human Resources	2011	$292,000	$185,257	$77.563	$—	$173,436	$728,256

(1) Salary represents the actual salary paid to the Named Executive Officer for each calendar year. The year 2012 contained 27 bi-weekly payment dates rather than the normal 26 bi-weekly payment dates. If 2012 salary data were adjusted to reflect only 26 payment dates the amounts would be: Emery - $671,000, Cleberg - $351,308, Evans - $414,231, Helmers - $307,115, and Myers - $303,884.

(2) Stock Awards represent the grant date fair value related to restricted stock 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, 2013. The amount included for performance shares is based on a payout of 100 percent of target, the level the award is expected to payout as determined as of the grant date. If the award were based on the maximum payout level, the amounts for the Stock Awards column would be increased to the following amounts:

	2013	2012	2011
David R. Emery	$1,555,042	$1,293,157	$996,808
Anthony S. Cleberg	$598,090	$591,137	$436,067
Linden R. Evans	$598,090	$941,132	$498,404
Steven J. Helmers	$403,715	$399,024	$336,414
Robert A. Myers	$328,954	$325,098	$249,209

BALANCE SHEET

Year: 2013

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	998,777,265	1,013,146,800	-1%
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	10,049,010	7,791,015	29%
9	107 Construction Work in Progress - Electric	18,216,818	77,221,568	-76%
10	108 (Less) Accumulated Depreciation	(353,473,411)	(368,557,131)	4%
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.	(3,131,929)	(3,229,335)	3%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	675,308,061	731,243,225	-8%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property			100%
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.			100%
20	123 Investments in Associated Companies			
21	123.1 Investments in Subsidiary Companies			
22	124 Other Investments	4,407,691	4,466,440	-1%
23	125 Sinking Funds			
24	**TOTAL Other Property & Investments**	4,407,691	4,466,440	-1%
25				
26	**Current & Accrued Assets**			
27	131 Cash	3,800,648	2,254,791	69%
28	132-134 Special Deposits			
29	135 Working Funds	4,175	4,175	
30	136 Temporary Cash Investments			
31	141 Notes Receivable	12,336	12,838	-4%
32	142 Customer Accounts Receivable	14,103,376	16,088,975	-12%
33	143 Other Accounts Receivable	1,391,980	698,081	99%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(102,274)	(219,900)	53%
35	145 Notes Receivable - Associated Companies	31,683,366	17,213,957	84%
36	146 Accounts Receivable - Associated Companies	5,027,346	4,934,314	2%
37	151 Fuel Stock	6,034,685	5,699,467	6%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	14,065,625	15,878,853	-11%
41	155 Merchandise			
42	156 Other Material & Supplies			100%
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed	532,623	1,581,718	-66%
45	165 Prepayments	4,571,479	4,375,998	4%
46	171 Interest & Dividends Receivable			
47	172 Rents Receivable			
48	173 Accrued Utility Revenues	9,003,643	9,719,096	-7%
49	174 Miscellaneous Current & Accrued Assets		118,151	-100%
50	**TOTAL Current & Accrued Assets**	90,129,008	78,360,514	15%

BALANCE SHEET

Year: 2013

Line	Account Number & Title	Last Year	This Year	% Change
1				
2	**Assets and Other Debits (cont.)**			
3				
4	**Deferred Debits**			
5				
6	181 Unamortized Debt Expense	2,938,009	2,813,821	4%
7	182.1 Extraordinary Property Losses			
8	182.2 Unrecovered Plant & Regulatory Study Costs			
8a	182.3 Other Regulatory Assets	50,615,318	42,439,077	19%
9	183 Prelim. Survey & Investigation Charges	2,283,565	3,074,967	-26%
10	184 Clearing Accounts	983,742	635,279	55%
11	185 Temporary Facilities			
12	186 Miscellaneous Deferred Debits	178,047	3,166,963	-94%
13	187 Deferred Losses from Disposition of Util. Plant			
14	188 Research, Devel. & Demonstration Expend.			
15	189 Unamortized Loss on Reacquired Debt	2,500,546	2,256,919	11%
16	190 Accumulated Deferred Income Taxes	31,047,369	17,628,335	76%
17	**TOTAL Deferred Debits**	90,546,596	72,015,361	26%
18				
19	**TOTAL Assets & Other Debits**	860,391,356	886,085,540	-3%
	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	257,887,269	280,060,005	-8%
35	217 (Less) Reacquired Capital Stock	(1,420,133)	(1,197,272)	-19%
36	**TOTAL Proprietary Capital**	319,458,461	341,854,058	-7%
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	15,055,000	15,055,000	
44	225 Unamortized Premium on Long Term Debt			
45	226 (Less) Unamort. Discount on L-Term Debt-Dr.	(111,090)	(106,950)	-4%
46	**TOTAL Long Term Debt**	269,943,910	269,948,050	0%

BALANCE SHEET

Year: 2013

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Total Liabilities and Other Credits (cont.)**				
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	557,900	609,030	-8%
9	228.3	Accumulated Provision for Pensions & Benefits			
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	2,705	140,418	-98%
12	**TOTAL Other Noncurrent Liabilities**		560,605	749,448	-25%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	13,680,020	25,359,449	-46%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	21,896,062	21,082,860	4%
20	235	Customer Deposits	941,217	972,985	-3%
21	236	Taxes Accrued	4,209,569	4,778,171	-12%
22	237	Interest Accrued	4,039,348	4,035,940	0%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	782,971	784,003	0%
27	242	Miscellaneous Current & Accrued Liabilities	5,118,521	4,411,393	16%
28	243	Obligations Under Capital Leases - Current			
29	**TOTAL Current & Accrued Liabilities**		50,667,708	61,424,801	-18%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,003,875	1,009,506	-1%
34	253	Other Deferred Credits	25,963,037	14,045,217	85%
34a	254	Other Regulatory Liabilities	17,252,794	12,911,115	34%
35	255	Accumulated Deferred Investment Tax Credits			
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	175,540,966	184,143,345	-5%
39	**TOTAL Deferred Credits**		219,760,672	212,109,183	4%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		860,391,356	886,085,540	-3%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2013

	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: 2013

		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	26,079	26,304	-1%
35	361	Structures & Improvements	5,970	5,970	
36	362	Station Equipment	232,127	(343,786)	168%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	368,621	390,220	-6%
39	365	Overhead Conductors & Devices	392,903	426,641	-8%
40	366	Underground Conduit	909	226	302%
41	367	Underground Conductors & Devices	6,706	13,144	-49%
42	368	Line Transformers	31,880	69,050	-54%
43	369	Services	5,568	9,801	-43%
44	370	Meters	1,276	1,276	
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	1,072,039	598,846	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED) Year: 2013

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment	(2,935)		#DIV/0!
12	397 Communication Equipment	13,291	13,750	-3%
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	10,356	13,750	
17				
18	**TOTAL Electric Plant in Service**	1,082,395	612,596	

MONTANA DEPRECIATION SUMMARY

Year: 2013

	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	598,846	953,401	965,848	
8	General	13,750	10,969	10,663	
9	**TOTAL**	612,596	964,370	976,511	

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		55.88%		
13	Preferred Stock				
14	Long Term Debt		44.12%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2013

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	27,086,197	30,172,736	-10%
6	Depreciation	27,620,661	28,124,961	-2%
7	Amortization			
8	Deferred Income Taxes - Net	24,627,508	13,448,918	83%
9	Investment Tax Credit Adjustments - Net			100%
10	Change in Operating Receivables - Net	2,924,920	(1,771,711)	265%
11	Change in Materials, Supplies & Inventories - Net	1,400,111	(2,527,631)	155%
12	Change in Operating Payables & Accrued Liabilities - Net	(902,944)	1,180,428	-176%
13	Allowance for Funds Used During Construction (AFUDC)	(324,622)	(367,564)	12%
14	Change in Other Assets & Liabilities - Net	(595,979)		#DIV/0!
15	Other Operating Activities (explained on attached page)	(9,259,256)	(1,696,795)	-446%
16	**Net Cash Provided by/(Used in) Operating Activities**	72,576,596	66,563,342	9%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(40,414,629)	(74,390,223)	46%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	235,809		#DIV/0!
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates	(25,152,067)	6,352,611	-496%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	233,234	(71,587)	426%
27	**Net Cash Provided by/(Used in) Investing Activities**	(65,097,653)	(68,109,199)	4%
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	(6,486,577)		#DIV/0!
39	Preferred Stock			
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt			
43	Dividends on Preferred Stock			
44	Dividends on Common Stock			
45	Other Financing Activities (explained on attached page)			
46	**Net Cash Provided by (Used in) Financing Activities**	(6,486,577)		#DIV/0!
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	992,366	(1,545,857)	164%
49	**Cash and Cash Equivalents at Beginning of Year**	2,812,457	3,804,823	-26%
50	**Cash and Cash Equivalents at End of Year**	3,804,823	2,258,966	68%

Attachment 23A

Footnotes for Statement of Cash Flow **Year: 2013**

Line 15, current year- Other Operating Activities includes:

$	3,940,050	employee benefit plans
$	(1,188,326)	prepaid income tax
$	(2,299,000)	benefit plan contribution
$	(1,563,308)	adjustments for regulatory activity
$	(2,326,383)	other current and non-current assets
$	1,740,172	other deferred credits
$	(1,696,795)	Total

Line 26, current year-Other Investing Activities

$	(71,587)	Increase in cash surrender value for PEP insurance

SCHEDULE 24

LONG TERM DEBT

Year: 2013

	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	72,175,479	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									
7	Campbell Cty	11/2004	10/2024	12,200,000	12,062,750	12,200,000	5.35%	652,700	5.35%
8									
9	1994 A Environ Improv	06/1994	06/2024	3,000,000	2,930,057	2,855,000	0.99%	25,922	0.91%
10	Bond								
11									
12									
13									
14									
15									
16									
17									
18									
19	Line 11, the 1994 A Bond has a variable interest rate. The weighted average rate for 2013 was 0.9896%								
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									
33	**TOTAL**			270,200,000	264,890,813	270,055,000		17,126,122	6.34%

SCHEDULE 25

PREFERRED STOCK

Year: 2013

	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										
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22										
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24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2013

		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: 2013

	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: 2013

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	613
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	(977)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	(364)
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	3,137
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	3,137
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	3,137
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	12
36		Commercial	22
37		Industrial	4
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	38
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	68,500
45		Average Annual Residential Cost per (Kwh) (Cents) *	7
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	391
48		Gross Plant per Customer	(9.58)

MONTANA CUSTOMER INFORMATION

Year: 2013

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties	2,922	12	22	4	38
2						
3						
4						
5						
6						
7						
8						
9						
10						
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28						
29						
30						
31						
32	**TOTAL Montana Customers**	2,922	12	22	4	38

MONTANA EMPLOYEE COUNTS

Year: 2013

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
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40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2013

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
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43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2013

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	13	1900	365	289,804	91,214
2	Feb.	19	1000	353	257,887	74,024
3	Mar.	13	1300	349	261,359	73,209
4	Apr.	9	1100	328	464,325	103,357
5	May	13	1700	319	232,608	84,131
6	Jun.	27	1600	379	263,781	90,352
7	Jul.	17	1700	407	274,617	66,427
8	Aug.	27	1600	422	277,218	76,979
9	Sep.	5	1400	404	277,964	118,161
10	Oct.	28	1900	328	284,574	110,935
11	Nov.	21	1900	356	264,584	80,421
12	Dec.	7	1700	403	228,624	33,637
13	**TOTAL**				3,377,345	1,002,847

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	1,768,483	Sales to Ultimate Consumers	1,724,258
3	Nuclear		(Include Interdepartmental)	
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	357,193
6	Other	33,374	for Resale	
7	(Less) Energy for Pumping			
8	**NET Generation**	1,801,857	Non-Requirements Sales	1,002,847
9	Purchases	1,441,286	for Resale	
10	Power Exchanges			
11	Received	191,782	Energy Furnished	
12	Delivered	57,580	Without Charge	
13	**NET Exchanges**	134,202		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	6,524,469	Electric Utility	
16	Delivered	6,524,469		
17	**NET Transmission Wheeling**	-	Total Energy Losses	293,047
18	Transmission by Others Losses			
19	**TOTAL**	3,377,345	**TOTAL**	3,377,345

SOURCES OF ELECTRIC SUPPLY

Year: 2013

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	2,074
2					
3	Thermal	Ben French	Rapid City, SD	10	(188)
4					
5	Thermal	Ben French	Rapid City, SD	24	(874)
6					
7	Thermal	Osage	Osage, WY	35	(150)
8					
9	Thermal	Wyodak	Gillette, WY	69	541,595
10					
11	Thermal	Neil Simpson I	Gillette, WY	20	137,959
12					
13	Thermal	Neil Simpson II	Gillette, WY	84	654,900
14					
15	Thermal	Lange	Rapid City, SD	39	8,391
16					
17	Thermal	Neil Simpson CT1	Gillette, WY	39	23,188
18					
19	Thermal	Wygen III	Gillette, WY	100	434,984
20					
21	Purchase	See Schedule 32			1,441,286
22					
23	Wheeling	See Schedule 32			-
24					
25	Total Interchange	See Schedule 32			134,202
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**			518	3,377,367

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2013

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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21							
22							
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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: 2013

	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	$4,690	$5,200	55	82	12	13
2	Commercial - Small	28,341	114,300	232	414	22	20
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	3,104,392	2,464,700	47,430	50,324	4	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**	$3,137,423	$2,584,200	47,717	50,820	38	35

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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 Commission 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, 2013, 2012 and 2011

(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 3).

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

Use of Estimates and Basis of Presentation

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.

We had the following regulatory assets and liabilities as follows as of December 31 (in thousands):

	Maximum Recovery Period (in years)	2013	2012
Regulatory assets:			
Unamortized loss on reacquired debt[a]	14	$ 2,257	$ 2,501
AFUDC[b]	45	8,327	8,460
Employee benefit plans[c]	13	15,233	27,001
Deferred energy costs[a]	1	7,711	6,892
Flow through accounting[a]	35	9,723	8,019
Other regulatory assets[a]	2	2,013	369
Total regulatory assets		$ 45,264	$ 53,242
Regulatory liabilities:			
Cost of removal for utility plant[a]	53	$ 30,467	$ 26,630
Employee benefit plans[d]	13	10,177	15,689
Other regulatory liabilities[e]	13	2,874	1,567
Total regulatory liabilities		$ 43,518	$ 43,886

(a) Recovery of costs but not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery of costs, we are allowed a return on approximately $24 million according to the approved rate case.
(d) Approximately $13 million is included in our rate base calculation as a reduction to rate base.
(e) Approximately $0.8 million is included in our rate base calculation as a reduction to rate base.

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 utility customers that are either higher or lower than the current rates and will be recovered or refunded 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 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 for Utility Plant - 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.

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. 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.

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 receivable 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 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 collectibility. 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):

	2013	2012
Accounts receivable trade	$ 16,300	$ 14,965
Unbilled revenues	9,719	9,004
Allowance for doubtful accounts	(220)	(102)
Net accounts receivable	$ 25,799	$ 23,867

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. Taxes collected from our customers are recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month, and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Receivables-customers, net on the accompanying Balance Sheets.

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. Included in the cost of regulated construction projects is AFUDC, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. 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, except as allowed under rate regulations, 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 2.1% in 2013, 2.2% in 2012 and 2.2% in 2011.

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 file a federal income tax return with other members of the Parent's consolidated group. For financial statement purposes, federal income taxes are allocated to the individual companies based on amounts calculated on a separate return basis.

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.

It is the Parent's 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 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.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax (expense) benefit on the Statements of Income. We account for uncertainty in income taxes recognized in the financial statements in accordance with accounting standards for income taxes. The unrecognized tax benefit is classified in Other - non-current liabilities on the accompanying Balance Sheets. See Note 6 for additional information.

Recently Adopted Accounting Standards

<u>Other Comprehensive Income: Presentation of Comprehensive Income, ASU 2011-05 and Deferral of the Effective Date for Amendments to the Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update 2011-05 and ASU 2011-12</u>

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. Ultimately FASB chose not to reinstate the reclassification adjustment requirements in ASU 2011-05 but instead issued ASU 2013-02 in February 2013. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, ASU 2013-02

In February 2013, the FASB issued new disclosure requirements for items reclassified out of AOCI to expand the disclosure requirements in ASC 220, Comprehensive Income, for presentation of changes in AOCI. ASU 2013-02 requires disclosure of (1) changes in components of other comprehensive income, (2) for items reclassified out of AOCI and into net income in their entirety, the effect of the reclassification on each affected net income line item and (3) cross references to other disclosures that provide additional detail for components of other comprehensive income that are not reclassified in their entirety to net income. Disclosures are required either on the face of the statements of income or as a separate disclosure in the notes to the financial statements. The new disclosure requirements are effective for interim and annual periods beginning after December 15, 2012. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements and Legislation

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

In July 2013, the FASB issued an amendment to accounting for income taxes which provides guidance on financial statement presentation of an unrecognized tax benefit when an NOL carryforward, a similar tax loss, or a tax credit carryforward exists. The objective in issuing this amendment is to eliminate diversity in practice resulting from a lack of guidance on this topic in current GAAP. Under the amendment, an entity must present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, in the financial statements as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward except under certain conditions. The amendment is effective for fiscal years beginning after December 15, 2013, and interim periods within those years and should be applied to all unrecognized tax benefits that exist as of the effective date. The adoption of this standard is not expected to have an impact on our financial position, results of operations or cash flows.

Final Tangible Personal Property Regulations, IRS Treasury Decision 9636

In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with amounts paid to acquire, produce, or improve tangible property. The regulations have the effect of a change in law and as a result the impact should be taken into account in the period of adoption. In general, such regulations apply to tax years beginning on or after January 1, 2014, with early adoption permitted. We expect that implementation of most, if not all, of the provisions of the final regulations to occur in 2014. Procedural guidance is expected from IRS in early 2014 to facilitate implementation. Analysis performed to date indicates no material impact to our financial statements.

(2) PROPERTY, PLANT AND EQUIPMENT

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

	2013	2013 Weighted Average Useful Life (in years)	2012	2012 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Maximum
Electric plant:						
Production	$ 512,444	51	$ 510,674	51	45	65
Transmission	115,149	46	115,092	46	40	60
Distribution	315,971	39	304,113	38	16	45
Plant acquisition adjustment [(a)]	4,870	32	4,870	32	32	32
General	70,228	22	71,802	22	8	45
Total plant-in-service	1,018,662		1,006,551			
Construction work in progress	77,222		18,217			
Total electric plant	1,095,884		1,024,768			
Less accumulated depreciation and amortization	(334,174)		(322,830)			
Electric plant net of accumulated depreciation and amortization	$ 761,710		$ 701,938			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 17 years remaining.

(3) 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 owns the remaining ownership percentage and 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, and are the operator of, 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 Wygen III and are obligated to make payments for costs associated with administrative services and a 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. Each of the respective owners is responsible for providing its own financing.

As of December 31, 2013, our interests in jointly-owned generating facilities and transmission systems included on our Balance Sheets were as follows (in thousands):

Interest in jointly-owned facilities	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 109,800	$ 192	$ 50,595
Transmission Tie	$ 19,648	$ —	$ 4,741
Wygen III	$ 131,468	$ 713	$ 10,593

(4) LONG-TERM DEBT

Long-term debt outstanding at December 31 was as follows (in thousands):

	Maturity Date	Interest Rate	2013	2012
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			(107)	(111)
Pollution control revenue bonds due 2024	October 1, 2024	5.35%	12,200	12,200
Series 94A Debt[(a)]	June 1, 2024	0.75%	2,855	2,855
Long-term debt			$ 269,948	$ 269,944

(a) Variable interest rate at December 31, 2013.

Net deferred financing costs of approximately $2.8 million and $2.9 million were recorded on the accompanying Balance Sheets in Other, non-current assets at December 31, 2013 and 2012, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.1 million, $0.2 million and $0.5 million for the years ended December 31, 2013, 2012 and 2011, respectively, are included in Interest expense on the accompanying Statements of Income.

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, 2013.

Long-term Debt Maturities

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

2014	$	—
2015	$	—
2016	$	—
2017	$	—
2018	$	—
Thereafter	$	270,055

(5) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments at December 31 were as follows (in thousands):

	2013		2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents (a)	$ 2,259	$ 2,259	$ 3,805	$ 3,805
Long-term debt, including current maturities (b)	$ 269,948	$ 317,531	$ 269,944	$ 359,567

(a) Fair value approximates carrying value due to either short-term length of maturity or variable interest rates that approximate prevailing market rates and therefore is classified in Level 1 in the fair value hierarchy.

(b) Long-term debt is valued using the market approach based on observable inputs of quoted market prices and yields available for debt instruments either directly or indirectly for similar maturities and debt ratings in active markets and therefore is classified in Level 2 in the fair value hierarchy. The carrying amount of our variable rate debt approximates fair value due to the variable interest rates with short reset periods. For additional information on our long-term debt, see Note 4 to the Financial Statements.

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

Cash and Cash Equivalents

Included in cash and cash equivalents is cash and overnight repurchase agreement accounts. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

(6) INCOME TAXES

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

	2013	2012	2011
Current	$ (163)	$ (10,319)	$ 14,921
Deferred	13,582	24,628	(2,931)
Total income tax expense	$ 13,419	$ 14,309	$ 11,990

The temporary differences which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2013	2012
Deferred tax assets:		
Employee benefits	$ 4,567	$ 5,094
Net operating loss	4,197	10,441
Regulatory liabilities	6,398	13,433
Other	2,193	2,381
Total deferred tax assets	17,355	31,349
Deferred tax liabilities:		
Accelerated depreciation and other plant related differences	(161,990)	(154,989)
AFUDC	(8,190)	(5,499)
Regulatory assets	(3,540)	(5,767)
Employee benefits	(3,467)	(3,610)
Deferred costs	(4,240)	(2,608)
Other	(1,067)	(1,163)
Total deferred tax liabilities	(182,494)	(173,636)
Net deferred tax assets (liabilities)	$ (165,139)	$ (142,287)

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

	2013	2012	2011
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.3)	(0.3)	(0.4)
Equity AFUDC	—	(0.1)	(0.6)
Flow through adjustments *	(2.5)	(3.5)	(3.4)
Prior year deferred adjustment **	—	3.6	—
Tax credits	(0.8)	—	—
Other	(0.6)	(0.1)	0.1
	30.8%	34.6%	30.7%

* The flow-through adjustments relate primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that 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. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow through method.

** The adjustment was a non-recurring unfavorable true-up attributable to property related deferred income taxes. The removal of the impact of such an adjustment is more appropriately reflective of the effective rate on a recurring basis.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in Other deferred credits and other liabilities on the accompanying Balance Sheet (in thousands):

	2013	2012
Unrecognized tax benefits at January 1	$ 2,078	$ 3,595
Reductions for prior year tax positions	(155)	(1,586)
Additions for current year tax positions	520	69
Unrecognized tax benefits at December 31	$ 2,443	$ 2,078

The reductions 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 $0.5 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2013 and 2012, the interest expense recognized was not material to our financial results.

We file income tax returns in the United States federal jurisdictions as a member of the BHC consolidated group. We do not anticipate that total unrecognized tax benefits will significantly change due to settlement of any audits or the expiration of statutes of limitations prior to December 31, 2014.

At December 31, 2013, we have federal NOL carry forward of $14 million, expiring in 2031. Ultimate usage of this NOL depends upon our ability to generate future taxable income, which is expected to occur within the prescribed carryforward period.

(7) COMPREHENSIVE INCOME

The components of the reclassification adjustments for the period, net of tax, included in Other Comprehensive Income were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges	Amounts Reclassified from AOCI	
		2013	2012
Gains and Losses on cash flow hedges			
Interest rate swaps	Interest expense	$ 64	$ 64
Income tax	Income tax benefit (expense)	(23)	(23)
Total reclassification adjustments related to cash flow hedges, net of tax		$ 41	$ 41
Amortization of defined benefit plans:			
Actuarial gain (loss)	Operations and maintenance	$ 66	$ —
Income tax	Income tax benefit (expense)	(23)	—
Total reclassification adjustments related to defined benefit plans, net of tax		$ 43	$ —

Derivatives designated as cash flow hedges relate to a treasury lock entered into in August 2002 to hedge $50 million of our First Mortgage Bonds due on August 15, 2032. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a $1.8 million loss. The treasury lock is treated as a cash flow hedge and the resulting loss is carried in Accumulated Other Comprehensive Loss and is being amortized over the life of the related bonds.

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

	Derivatives Designated as Cash Flow Hedges		
	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2012	$ (760)	$ (660)	$ (1,420)
Other comprehensive income (loss)	41	182	223
As of December 31, 2013	$ (719)	$ (478)	$ (1,197)

	Derivatives Designated as Cash Flow Hedges		
	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2011	$ (801)	$ (489)	$ (1,290)
Other comprehensive income (loss)	41	(171)	(130)
As of December 31, 2012	$ (760)	$ (660)	$ (1,420)

(8) EMPLOYEE BENEFIT PLANS

Funded Status of Benefit Plans

The funded status of the postretirement benefit plan is required to be recognized in the statement of financial position. The funded status for the 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. As of December 31, 2013, the unfunded status of our Defined Benefit Pension Plan was $3.8 million, the unfunded status of our Supplemental Non-qualified Defined Benefit Plans was $3.1 million and the unfunded status of our Non-pension Defined Benefit Postretirement Healthcare Plans was $5.9 million.

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.

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 Plan was frozen. Plan benefits are based on years of service and calculations of average earnings during a specific time period prior to retirement.

As of December 31, 2012, certain Plan investments were transferred to a Master Trust that was established for the investment of assets of the Plan and other Employer-sponsored retirement plans. Each participating retirement plan has an undivided interest in the Master Trust.

On October 29, 2012, the Board of Directors approved a new Investment Policy. The objective of the Investment Policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Plans' beneficiaries. To meet this objective, our pension plan assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Plans' benefit payment obligations and an asset allocation that will comprise a mix of return-seeking and liability-hedging assets. Our Pension Plan 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, fixed income and hedged investments. The expected long-term rate of return for investments was 7.25% and 7.25% for the 2013 and 2012 plan years, respectively.

Pension Plan Assets

The percentages of total plan asset fair value by investment category of our Pension Plan assets at December 31 were as follows:

	2013	2012
Equity securities	26%	51%
Real estate	4%	—%
Fixed income funds	58%	48%
Cash and cash equivalents	1%	1%
Hedge funds	11%	—%
Total	100%	100%

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. The Supplemental Plans are subject to various vesting schedules.

Supplemental Plan Assets

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plan

Employees who are participants in our Non-Pension Postretirement Healthcare Plan ("Healthcare Plan") and who retire on or after attaining minimum age and years of service requirements 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 have 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

We do not fund our Healthcare Plans. We fund on a cash basis as benefits are paid.

Plan Contributions and Estimated Cash Flows

Contributions made to the Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Contributions for the years ended December 31 were as follows (in thousands):

	2013	2012
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 2,299	$ 6,835
Non-pension Defined Benefit Postretirement Healthcare Plan	$ 578	$ 835
Supplemental Non-qualified Defined Benefit Plan	$ 217	$ 256
Defined Contribution Plans		
Company Retirement Contribution	$ 421	$ 404
Matching Contributions	$ 1,301	$ 1,328

We do not intend to make a contribution to our employee defined benefit pension plan in 2014.

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	**2013**			
	Level 1	Level 2	Level 3	Total Fair Value
AXA Equitable General Fixed Income	$ —	$ 213	$ —	$ 213
Common Collective Trust - Cash and Cash Equivalents	—	252	—	252
Common collective trust - equity	—	14,833	—	14,833
Common collective trust - fixed income	—	32,742	—	32,742
Common collective trust - real estate	—	682	1,718	2,400
Hedge funds	—	—	5,965	5,965
Total investments measured at fair value	$ —	$ 48,722	$ 7,683	$ 56,405

Defined Benefit Pension Plan	**2012**			
	Level 1	Level 2	Level 3	Total Fair Value
Cash and cash equivalents	$ 535	$ —	$ —	$ 535
Common collective trust - equity	—	27,267	—	27,267
Common collective trust - fixed income	—	21,127	—	21,127
Structured products	—	4,536	—	4,536
Total investments measured at fair value	$ 535	$ 52,930	$ —	$ 53,465

Cash and Cash Equivalents: This category is comprised of the AXA Equitable General Fixed Income Fund wand Common Collective Trusts - cash and cash equivalents. The AXA Equitable General Fixed Income Fund is a fund of diversified portfolios, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately place bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates at which loans with similar characteristics. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service provides with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer.

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 on the date of valuation.

Common Collective Trust-Real Estate Fund: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments, and rely on these reports for pricing the units of the fund. Certain of the funds' assets contain participant withdrawal policy and, therefore, are categorized as Level 3. The funds without participant withdrawal limitations are categorized as Level 2.

Hedge Funds: Hedge funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. Generally, shares may be redeemed at the end of each quarter, after a lockup period of one-year, with a 65 day notice and is limited to a percentage of total net asset value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

Structured Products: Investments are created through the process of financial engineering (that is, by combining underlying securities like equity, bonds, or indices with derivatives). The value of derivative securities, such as options, forwards and swaps is determined by (respectively, derives from) the prices of the underlying securities.

The following table sets forth a summary of changes in the fair value of the Defined Benefit Pension Plans' Level 3 assets for the period ended December 31 (in thousands):

		2013
Balance, beginning of period	$	—
Transfers		1,550
Purchase		5,834
Unrealized gain (loss)		317
Realized gain (loss)		(3)
Settlements		(15)
Balance, end of period	$	7,683

The following table presents the quantitative information about Level 3 fair value measurements (dollars in thousands):

		Fair Value at December 31, 2013	Valuation Technique	Level 3 Input	Range (Weighted) Average
Assets:					
Common Collective Trust - Real Estate (a)	$	1,718	Market Approach	Redemption Restriction	N/A
Hedge Funds (b)	$	5,965	Market Approach	Redemption Restriction	N/A

(a) The underlying net asset value in the Common Collective Trust - Real Estate fund is determined by appraisal of the properties held in the Trust. As part of the Trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with the professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the Trustee along with the annual schedule of investments and rely on these reports for pricing the units of the fund. The fund does contain a participant withdrawal policy.

(b) The fair value of Level 3 is determined based on pricing provided or reviewed by third-party administrator to our investment managers. While the input amounts used by the pricing vendor in determining fair value are not provided, and therefore, unavailable for our review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar asset classes. Additionally, the audited financial statements of the funds will be reviewed at the time they are issued.

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 Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2013	2012	2013	2012	2013	2012
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 69,820	$ 65,557	$ 3,427	$ 2,292	$ 6,766	$ 8,207
Service cost	852	765	—	—	216	214
Interest cost	2,969	2,969	133	104	239	343
Actuarial loss (gain)	(7,818)	4,510	(212)	1,287	(459)	(1,748)
Amendments (a)	—	—	—	—	(342)	—
Benefits paid	(4,850)	(2,850)	(217)	(256)	(1,045)	(835)
Asset transfer (to) from affiliate	(750)	(1,131)	—	—	(75)	26
Plan curtailment reduction	—	—	—	—	—	—
Medicare Part D adjustment	—	—	—	—	82	71
Plan participants' contributions	—	—	—	—	468	488
Projected benefit obligation at end of year	$ 60,223	$ 69,820	$ 3,131	$ 3,427	$ 5,850	$ 6,766

(a) Reflects Board of Directors approval of increase to Company's contribution to RMSA account.

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

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2013	2012	2013	2012	2013	2012
Beginning market value of plan assets	$ 53,465	$ 45,017	$ —	$ —	$ —	$ —
Investment income	6,070	5,240	—	—	—	—
Benefits paid	(4,850)	(2,850)	—	—	—	—
Employer contributions	2,299	6,835	—	—	—	—
Asset transfer to affiliate	(579)	(777)	—	—	—	—
Ending market value of plan assets	$ 56,405	$ 53,465	$ —	$ —	$ —	$ —

Amounts recognized in the Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plan	
	2013	2012	2013	2012	2013	2012
Regulatory asset (liability)	$ 13,735	$ 26,683	$ —	$ —	$ 2,781	$ (2,174)
Current (liability)	$ —	$ —	$ (216)	$ (216)	$ (491)	$ (438)
Non-current (liability)	$ (3,818)	$ (16,356)	$ (2,915)	$ (3,211)	$ (5,372)	$ (6,321)

Accumulated Benefit Obligation (dollars in thousands)

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2013	2012	2013	2012	2013	2012
Accumulated benefit obligation	$ 55,283	$ 63,417	$ 3,131	$ 3,427	$ 5,850	$ 6,766

Components of Net Periodic Expense (dollars in thousands)

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Service cost	$ 852	$ 765	$ 798	$ —	$ —	$ —	$ 216	$ 214	$ 210
Interest cost	2,969	2,969	3,092	133	104	114	239	343	365
Expected return on assets	(3,764)	(3,139)	(3,619)	—	—	—	—	—	—
Amortization of prior service cost (credits)	43	57	62	—	—	—	(278)	(278)	(314)
Amortization of transition obligation	2,609	—	—	—	—	—	—	—	—
Recognized net actuarial loss (gain)	—	2,599	1,486	66	55	48	9	139	163
Curtailment expense	—	—	—	—	—	—	—	—	—
Net periodic expense	$ 2,709	$ 3,251	$ 1,819	$ 199	$ 159	$ 162	$ 186	$ 418	$ 424

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 Pension Plan		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2013	2012	2013	2012	2013	2012
Net loss	$ —	$ —	$ (479)	$ (660)	$ —	$ —
Prior service cost	—	—	—	—	—	—
Total accumulated other comprehensive income (loss)	$ —	$ —	$ (479)	$ (660)	$ —	$ —

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 2014 were as follows (in thousands):

	Defined Benefits Pension Plan	Supplemental Non-qualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
Net loss	$ 611	$ 29	$ —
Prior service cost	28	—	(206)
Total net periodic benefit cost expected to be recognized during calendar year 2014	$ 639	$ 29	$ (206)

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Weighted-average assumptions used to determine benefit obligations:									
Discount rate	5.10%	4.35%	4.65%	4.68%	4.25%	4.70%	4.45%	3.65%	4.35%
Rate of increase in compensation levels	3.86%	3.91%	3.67%	N/A	N/A	N/A	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:									
Discount rate	4.35%	4.65%	5.50%	3.88%	4.70%	5.00%	3.65%	4.35%	5.00%
Expected long-term rate of return on assets*	7.25%	7.25%	7.75%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	3.91%	3.67%	3.70%	N/A	N/A	N/A	N/A	N/A	N/A

* The expected rate of return on plan assets is 6.75% for the calculation of the 2014 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	2013	2012
Healthcare trend rate pre-65		
Trend for next year	7.50%	7.75%
Ultimate trend rate	4.50%	4.50%
Year Ultimate Trend Reached	2027	2027
Healthcare trend rate post-65		
Trend for next year	6.25%	6.50%
Ultimate trend rate	4.50%	4.50%
Year Ultimate Trend Reached	2026	2026

We do not pre-fund our post-retirement benefit plan. The table below shows the estimated impacts of an increase or decrease to our healthcare trend rate for our Retiree Health Care Plan (dollars in thousands):

Change in Assumed Trend Rate	Service and Interest Costs	Accumulated Periodic Postretirement Benefit Obligation
1% increase	$ 9	$ 179
1% decrease	$ (9)	$ (165)

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

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
2014	$ 3,177	$ 217	$ 491
2015	$ 3,227	$ 214	$ 432
2016	$ 3,270	$ 184	$ 410
2017	$ 3,367	$ 213	$ 418
2018	$ 3,483	$ 210	$ 473
2019-2023	$ 20,002	$ 1,271	$ 2,483

Defined Contribution Plan

The Parent sponsors a 401(k) retirement savings plan in which our 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.

(9) RELATED-PARTY TRANSACTIONS

Non-Cash Dividend to Parent

We have recorded a non-cash dividend to our Parent for approximately $8.0 million and $44 million in 2013 and 2012 and decreased the utility money pool note receivable, net for approximately $8.0 million and $44 million, in 2013 and 2012 respectively.

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):

	2013	2012
Receivable - affiliates	$ 4,934	$ 5,027
Accounts payable - affiliates	$ 21,082	$ 21,896

Money Pool Notes Receivable and Notes Payable

We have a Utility Money Pool Agreement (the Agreement) with BHC, Cheyenne Light and Black Hills Energy. Under the agreement, we may borrow from BHC however the Agreement restricts us from loaning funds to BHC or to any of BHCs' non-utility subsidiaries. The Agreement does not restrict us from making dividends to BHC. Borrowings under the agreement bear interest at the weighted average daily cost of our parent company's credit facility borrowings 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 1.0%.

The cost of borrowing under the Utility Money Pool was 1.60% at December 31, 2013.

We had the following balances with the Utility Money Pool as of December 31 (in thousands):

	2013	2012
Notes receivable (payable), net	$ 17,292	$ 31,645

Net interest income (expense) relating to the Utility Money Pool for the years ended December 31, was as follows (in thousands)

	2013	2012	2011
Net interest income (expense)	$ 505	$ 617	$ 1,414

Other Balances and Transactions

We have the following Power Purchase and Transmission Services Agreements with affiliated entities:

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

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

	2013	2012	2011
	(in thousands)		
Revenues:			
Energy sold to Cheyenne Light	$ 1,338	$ 2,372	$ 957
Rent from electric properties	$ 3,627	$ 2,661	$ 7,523
Purchases:			
Purchase of coal from WRDC	$ 18,542	$ 20,690	$ 21,319
Purchase of excess energy from Cheyenne Light	$ 3,640	$ 3,139	$ 4,127
Purchase of renewable wind energy from Cheyenne Light - Happy Jack	$ 1,886	$ 1,988	$ 1,955
Purchase of renewable wind energy from Cheyenne Light - Silver Sage	$ 3,207	$ 3,269	$ 3,281
Corporate support services from Parent, Black Hills Service Company and Black Hills Utility Holdings	$ 30,738	$ 24,163	$ 18,567

(10) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2013	2012	2011
	(in thousands)		
Non-cash investing and financing activities -			
Property, plant and equipment acquired with accrued liabilities	$ 13,590	$ 3,969	$ 1,882
Non-cash decrease to money pool note receivable, net	$ (8,000)	$ (43,984)	$ —
Non-cash dividend to Parent company	$ 8,000	$ 43,984	$ —
Supplemental disclosure of cash flow information:			
Cash (paid) refunded during the period for -			
Interest (net of amounts capitalized)	$ (19,174)	$ (17,099)	$ (16,294)
Income taxes	$ 219	$ 7,176	$ (15,347)

(11) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

We have the following power purchase and transmission agreements, not including related party agreements, as of December 31, 2013 (see Note 9 for information on related party agreements):

- 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; and
- An agreement with Thunder Creek for gas transport capacity, expiring in October 31, 2019.

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

Contract	Contract Type		2013		2012		2011
PacifiCorp	Electric capacity and energy	$	13,026	$	13,224	$	12,515
PacifiCorp	Transmission access	$	1,384	$	1,215	$	1,215
Thunder Creek	Gas transport capacity	$	633	$	633	$	633

Future Contractual Obligations

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

2014	$	12,451
2015	$	12,443
2016	$	12,443
2017	$	12,443
2018	$	6,133
Thereafter	$	28,764

Long-Term Power Sales Agreements

We have the following power sales agreements as of December 31, 2013:

- 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 energy and capacity purchase requirements decrease over the term of the agreement; and

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

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A fire investigator concluded that the fire was caused by the failure of a transmission structure owned, operated and maintained by us. On April 16, 2013, thirty-five private parties filed suit in the United States District Court for the District of Wyoming, asserting claims for damages against us based upon allegations of negligence, negligence per se, common law nuisance, and trespass. Although not currently included in the lawsuit, we also received written damage claims from an additional landowner and from the State of Wyoming. Altogether the claims seek recovery for fire suppression, reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate, for a current total amount of $15 million. In addition to claims for these compensatory damages, the lawsuit seeks recovery of punitive damages. Our investigation of the cause and origin of the fire is ongoing. We have denied and will vigorously defend all claims arising out of the fire, pending the completion of our investigation. Given the uncertainty of litigation, however, a loss related to the fire, the litigation and related claims, is reasonably possible. We cannot reasonably estimate the amount of a potential loss because our investigation is ongoing, and because damage claims are currently incomplete or undocumented. Further claims may be presented by these and other parties. We cannot predict the outcome of our investigation, the viability of alleged claims or the outcome of the litigation. Based upon information currently available, however, management does not expect the claims, if determined adversely to us, to have a material adverse effect upon our financial condition, results of operations or cash flows.

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.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. They can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Air

Our generation facilities are subject to federal, state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, carbon monoxide, SO_2, NO_X, mercury particulate matter and GHG. Power generating facilities burning fossil fuels emit each of the foregoing pollutants and, therefore, are subject to substantial regulation and enforcement oversight by various governmental agencies.

Title IV of the Clean Air Act applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT II, Lange CT, Wygen III and Wyodak plants. Title IV of the Clean Air Act created an SO_2 allowance trading program as part of the federal acid rain program. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2042.

The EPA issued the Industrial and Commercial Boiler Regulations for Area Sources of Hazardous Air Pollutants, with updates which impose emission limits, fuel requirements and monitoring requirements. The rule has a compliance deadline of March 21, 2014. In anticipation of this rule, we suspended operations at the Osage plant on October 1, 2010 and as a result of this rule, we suspended operations at the Ben French facility on August 31, 2012 with plans to retire Osage, Ben French and Neil Simpson I on or before March 21, 2014. While the net book value of these plants is estimated to be insignificant at the time of retirement, we would reasonably expect any remaining value to be recovered through future rates.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, at which operations have been suspended, has an on-site ash impoundment that is near capacity. An application to close the impoundment was approved by the State of Wyoming on April 13, 2012. Site closure work was completed in 2013 and post closure monitoring activities will continue for 30 years. In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed and post closure monitoring will continue for 30 years.

(12) 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
2013				
Operating revenues	$ 59,817	$ 60,832	$ 67,268	$ 66,110
Operating income	$ 12,503	$ 14,293	$ 18,704	$ 16,844
Net income	$ 5,582	$ 6,652	$ 9,298	$ 8,641
2012				
Operating revenues	$ 62,270	$ 58,372	$ 61,134	$ 61,533
Operating income	$ 12,742	$ 13,859	$ 15,361	$ 15,619
Net income	$ 6,053	$ 6,727	$ 8,147	$ 6,159