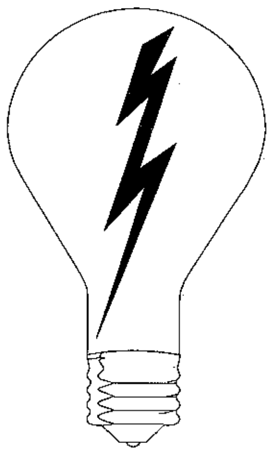
YEAR ENDING 2019

ANNUAL REPORT
OF

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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IDENTIFICATION

Year: **2019**

1.	Legal Name of Respondent:	Black Hills Power, Inc.
2.	Name Under Which Respondent Does Business:	Black Hills Energy
3.	Date Utility Service First Offered in Montana	2/23/1968
4.	Address to send Correspondence Concerning Report:	PO Box 1400 Rapid City, SD 57709-1400
5.	Person Responsible for This Report:	Jason Keil Manager Regulatory
5a.	Telephone Number:	605-721-1502

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 7001 Mt. Rushmore Road Rapid City, SD 57702
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	Linden R. Evans	Rapid City, SD	$ 0 (a)
2	Richard W. Kinzley	Rapid City, SD	$ 0 (a)
3	Brian G. Iverson	Rapid City, SD	$ 0 (a)
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8	(a) As officers of the company, they receive no compensation for their services as directors		
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Officers

Year: 2019

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman, President, and Chief Executive Officer (1) & (2)		Linden R. Evans
2	Senior Vice President and Chief Financial Officer		Richard W. Kinzley
3	Senior Vice President, General Counsel, Chief Compliance Officer and		Brian G. Iverson
4	Assistant Corporate Secretary (3)		
5	Senior Vice President - Chief Information Officer		Scott A. Buchholz
6	Senior Vice President - Chief Human Resources Officer		Jennifer C. Landis
7	Senior Vice President - Growth and Strategy (6)		Karen Beachy
8	Senior Vice President - Utility Operations (7)		Stuart A. Wevik
9	Vice President - Corporate Controller and Treasurer		Kimberly F. Nooney
10	Vice President and Chief Risk Officer		Esther J. Newbrough
11	Vice President - Regulatory and Finance		Marne M. Jones
12	Vice President - Governance, Corporate Secretary and Deputy General Counsel (8)		Amy K. Koenig
13	Vice President - Electric Utilities (9)		Nick Gardner
14	Vice President - Tax		Donna E. Genora
15	Vice Predient - Regulatory Strategy		Kyle D. White
16	Vice President - Electric Asset Optimization (10)		Mark L. Lux
17	Vice President - Mine Operations and Power Delivery (11)		Marc Ostrem
18	Vice President - Customer Service		Mark E. Stege
19	Vice President - BHE SD (9)		Vacant
20	Vice President - Gas Asset Optimization		Jodi Culp
21			
22			
23			
24			
25	(1) David R. Emery was removed as Chairman and Chief Executive Officer and Director of Black Hills Power, Inc.		
26	effective January 1, 2019 in preparation for his upcoming retirement.		
27	(2) Linden R. Evans' title changed from President and Chief Operating Officer to Chairman, President and		
28	Chief Executive Officer effective January 1, 2019.		
29	(3) Brian G. Iverson's title changed from Senior Vice President and General Counsel (also Chief Compliance		
30	Officer and Assistant Corporate Secretary) to Senior Vice President, General Counsel and Corporate Secretary		
31	(also Chief Compliance Officer) effective February 1, 2019 and to Senior Vice President, General Counsel,		
32	Chief Compliance Officer and Assistant Corporate Secretary effective August 26, 2019.		
33	(4) Roxann R. Basham's title changed from Vice President – Governance and Corporate Secretary to Vice		
34	President – Governance effective February 1, 2019 and retired effective May 1, 2019.		
35	(5) Perry S. Krush, Vice President – Facilities, retired effective March 1, 2019.		
36	(6) Karen H. Beachy's title changed from Vice President – Growth and Strategy to Senior Vice President – Growth		
37	and Strategy effective August 26, 2019.		
38	(7) Stuart A. Wevik's title changed from Group Vice President – Electric Utilities to Senior Vice		
39	President – Utility Operations effective August 26, 2019.		
40	(8) Amy K. Koenig's title changed from Assistant Corporate Secretary to Vice President – Governance,		
41	Corporate Secretary and Deputy General Counsel effective August 26, 2019.		
42	(9) Nick Gardner title changed from Vice President – Operations to Vice President – Electric Utilities		
43	effective August 26, 2019.		
44	(10) Mark Lux's title changed from Vice President – Energy Innovation to Vice President – Electric		
45	Asset Optimization effective August 26, 2019.		
46	(11) Marc Ostrem's title changed from Vice President – Power Delivery, Safety and Environmental to		
47	Vice President – Mine Operations and Power Delivery effective August 26, 2019		
48			

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 4**

CORPORATE STRUCTURE

Year: 2019

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	46,901,602	100.00%
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42				100.00%
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50	**TOTAL**		46,901,602	

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 5**

CORPORATE ALLOCATIONS

Year: 2019

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

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY Year: 2019

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)	17,040,737	27.65%	1,158,770
2	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	6,403,302	3.57%	435,425
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	41,948,272	69.29%	2,852,483
4	Cheyenne Light Fuel and Power	Renewable Wind Energy Sales	Fixed PPA Pricing	5,547,079	3.09%	377,201
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32	**TOTAL**			70,939,390		4,823,879

Company Name: Black Hills Power d/b/a Black Hills Energy SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2019

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	995,475	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point open Access Transmission Tariff	21,203	100.00%	
3	Cheyenne Light Fuel and Power	Transmission Service	Point to Point Open Access Transmission Tariff Fair Market	4,034,982	4.27%	274,379
4	Black Hills Colorado Electric	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	3,850,924	3.18%	261,863
5	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	7,435,661	7.88%	505,625
6	Cheyenne Light Fuel and Power	Neil Simpson Complex	Fair Market Value (based on similar arms-length transactions	6,863,187	7.27%	466,697
7	Cheyenne Light Fuel and Power	Environmental Complex	Fair Market Value (based on similar arms-length transactions	77,677	0.08%	5,282
8	Black Hills Service Company	Corporate Headquarter Sha	Revenue Requirement	12,026,412	24.34%	817,796
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30				35,305,521		2,331,642

MONTANA UTILITY INCOME STATEMENT

Year: 2019

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	297,591,568	302,510,728	1.65%
2					
3		Operating Expenses			
4	401	Operation Expenses	150,011,461	143,722,720	-4.19%
5	402	Maintenance Expense	22,478,896	22,522,807	0.20%
6	403	Depreciation Expense	37,517,508	39,299,264	4.75%
7	404-405	Amortization of Electric Plant	2,055,830	1,985,481	-3.42%
8	406	Amort. of Plant Acquisition Adjustments	97,406	97,406	
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	7,793,518	10,309,471	32.28%
12	409.1	Income Taxes - Federal	5,503,822	13,776,092	150.30%
13		- Other		200	#DIV/0!
14	410.1	Provision for Deferred Income Taxes	18,222,269	8,025,019	-55.96%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(13,007,608)	(12,306,045)	5.39%
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**	230,673,102	227,432,415	-1.40%
21		**NET UTILITY OPERATING INCOME**	66,918,466	75,078,313	12.19%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	7,277	7,995	9.87%
3	442	Commercial & Industrial - Small	19,176	19,249	0.38%
4		Commercial & Industrial - Large	8,149,045	9,279,330	13.87%
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**	8,175,498	9,306,574	13.83%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	8,175,498	9,306,574	13.83%
14	449.1	(Less) Provision for Rate Refunds	637,517	601,469	-5.65%
15					
16		**TOTAL Revenue Net of Provision for Refunds**	7,537,981	8,705,105	15.48%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	11	9	-18.18%
19	451	Miscellaneous Service Revenues	8		-100.00%
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**	19	9	-52.63%
26		**Total Electric Operating Revenues**	7,538,000	8,705,114	15.48%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2019

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	843,984	1,108,429	31.33%
6	501 Fuel	20,474,508	19,757,787	-3.50%
7	502 Steam Expenses	1,869,318	1,494,280	-20.06%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	689,168	591,117	-14.23%
11	506 Miscellaneous Steam Power Expenses	1,622,962	1,523,603	-6.12%
12	507 Rents	2,524,112	2,525,546	0.06%
13				
14	TOTAL Operation - Steam	28,024,052	27,000,762	-3.65%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	2,641,141	1,289,368	-51.18%
18	511 Maintenance of Structures	567,431	792,912	39.74%
19	512 Maintenance of Boiler Plant	5,039,160	4,284,048	-14.98%
20	513 Maintenance of Electric Plant	1,028,103	897,488	-12.70%
21	514 Maintenance of Miscellaneous Steam Plant	84,764	55,071	-35.03%
22				
23	TOTAL Maintenance - Steam	9,360,599	7,318,887	-21.81%
24				
25	**TOTAL Steam Power Production Expenses**	37,384,651	34,319,649	-8.20%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

Company Name: Black Hills Power d/b/a Black Hills Energy

	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	1,226,499	969,064	-20.99%
27	547 Fuel	4,658,536	6,430,427	38.04%
28	548 Generation Expenses	82,667	99,835	20.77%
29	549 Miscellaneous Other Power Gen. Expenses	387,281	360,819	-6.83%
30	550 Rents	275,377	269,310	-2.20%
31				
32	TOTAL Operation - Other	6,630,360	8,129,455	22.61%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	69,046	22,481	-67.44%
36	552 Maintenance of Structures	82,270	25,873	-68.55%
37	553 Maintenance of Generating & Electric Plant	2,016,622	2,313,588	14.73%
38	554 Maintenance of Misc. Other Power Gen. Plant	118,572	35,180	-70.33%
39				
40	TOTAL Maintenance - Other	2,286,510	2,397,122	4.84%
41				
42	**TOTAL Other Power Production Expenses**	8,916,870	10,526,577	18.05%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	47,177,200	37,066,951	-21.43%
46	556 System Control & Load Dispatching	1,528,605	1,378,605	-9.81%
47	557 Other Expenses	110		-100.00%
48				
49	TOTAL Other Power Supply Expenses	48705915	38,445,556	-21.07%
50				
51	**TOTAL Power Production Expenses**	95,007,436	83,291,782	-12.33%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2019

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	1,117,549	857,868	-23.24%
4	561	Load Dispatching	2,820,026	2,521,463	-10.59%
5	562	Station Expenses	485,162	407,214	-16.07%
6	563	Overhead Line Expenses	129,797	318,140	145.11%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	22,605,598	23,638,278	4.57%
9	566	Miscellaneous Transmission Expenses	1,230,868	267,610	-78.26%
10	567	Rents		23,307	#DIV/0!
11					
12		TOTAL Operation - Transmission	28,389,000	28,033,880	-1.25%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	91		-100.00%
15	569	Maintenance of Structures	5,546	4,730	-14.71%
16	570	Maintenance of Station Equipment	131,783	193,696	46.98%
17	571	Maintenance of Overhead Lines	538,498	667,516	23.96%
18	572	Maintenance of Underground Lines	2,176		-100.00%
19	573	Maintenance of Misc. Transmission Plant	1,048	16,561	1480.25%
20					
21		TOTAL Maintenance - Transmission	679,142	882,503	29.94%
22					
23		**TOTAL Transmission Expenses**	29,068,142	28,916,383	-0.52%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	1,757,662	1,553,697	-11.60%
28	581	Load Dispatching	468,704	371,890	-20.66%
29	582	Station Expenses	473,273	546,033	15.37%
30	583	Overhead Line Expenses	436,235	539,739	23.73%
31	584	Underground Line Expenses	352,860	413,906	17.30%
32	585	Street Lighting & Signal System Expenses	85,456	80,586	-5.70%
33	586	Meter Expenses	699,831	560,372	-19.93%
34	587	Customer Installations Expenses	287,261	283,660	-1.25%
35	588	Miscellaneous Distribution Expenses	2,387,726	2,009,082	-15.86%
36	589	Rents	15,629	51,357	228.60%
37					
38		TOTAL Operation - Distribution	6,964,637	6,410,322	-7.96%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	26,297	38,082	44.81%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	115,204	156,290	35.66%
43	593	Maintenance of Overhead Lines	7,476,893	8,666,654	15.91%
44	594	Maintenance of Underground Lines	501,713	491,438	-2.05%
45	595	Maintenance of Line Transformers	87,702	61,617	-29.74%
46	596	Maintenance of Street Lighting, Signal Systems	67,061	51,186	-23.67%
47	597	Maintenance of Meters	70,705	64,617	-8.61%
48	598	Maintenance of Miscellaneous Dist. Plant	237,328	77,318	-67.42%
49					
50		TOTAL Maintenance - Distribution	8,582,903	9,607,202	11.93%
51					
52		**TOTAL Distribution Expenses**	15,547,540	16,017,524	3.02%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2019

		Account Number & Title	Last Year	This Year	% Change
1		Customer Accounts Expenses			
2	Operation				
3	901	Supervision	86,288	59,980	-30.49%
4	902	Meter Reading Expenses	10,988	17,738	61.43%
5	903	Customer Records & Collection Expenses	1,507,415	1,440,744	-4.42%
6	904	Uncollectible Accounts Expenses	516,082	608,531	17.91%
7	905	Miscellaneous Customer Accounts Expenses	259,346	256,346	-1.16%
8					
9		TOTAL Customer Accounts Expenses	2,380,119	2,383,339	0.14%
10					
11		Customer Service & Information Expenses			
12	Operation				
13	907	Supervision	63,978	27,729	-56.66%
14	908	Customer Assistance Expenses	748,233	384,022	-48.68%
15	909	Informational & Instructional Adv. Expenses	25,730	9,661	-62.45%
16	910	Miscellaneous Customer Service & Info. Exp.	102,806	46,299	-54.96%
17					
18		TOTAL Customer Service & Info Expenses	940,747	467,711	-50.28%
19					
20		Sales Expenses			
21	Operation				
22	911	Supervision	1,156	104	-91.00%
23	912	Demonstrating & Selling Expenses	15,139	958	-93.67%
24	913	Advertising Expenses	52	2,141	4017.31%
25	916	Miscellaneous Sales Expenses			
26					
27		TOTAL Sales Expenses	16,347	3,203	-80.41%
28					
29		Administrative & General Expenses			
30	Operation				
31	920	Administrative & General Salaries	16,582,372	13,368,352	-19.38%
32	921	Office Supplies & Expenses	4,078,950	4,346,774	6.57%
33	922	(Less) Administrative Expenses Transferred - Cr.	(3,283,615)	(2,959,147)	9.88%
34	923	Outside Services Employed	3,985,847	4,026,888	1.03%
35	924	Property Insurance	509,758	591,919	16.12%
36	925	Injuries & Damages	1,399,457	1,601,542	14.44%
37	926	Employee Pensions & Benefits	75,763	6,450,351	8413.85%
38	927	Franchise Requirements			
39	928	Regulatory Commission Expenses	839,823	770,070	-8.31%
40	929	(Less) Duplicate Charges - Cr.	(256,178)	(237,828)	7.16%
41	930.1	General Advertising Expenses	304,742	481,258	57.92%
42	930.2	Miscellaneous General Expenses	1,102,560	1,702,647	54.43%
43	931	Rents	2,620,805	2,705,666	3.24%
44					
45		TOTAL Operation - Admin. & General	27,960,284	32,848,492	17.48%
46	Maintenance				
47	935	Maintenance of General Plant	1,569,742	2,317,093	47.61%
48					
49		**TOTAL Administrative & General Expenses**	29,530,026	35,165,585	19.08%
50					
51		**TOTAL Operation & Maintenance Expenses**	172,490,357	166,245,527	-3.62%

MONTANA TAXES OTHER THAN INCOME

Year: 2019

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	3,799	6,633	74.61%
5	Montana PSC	17,895	21,951	22.67%
6	Franchise Taxes			
7	Property Taxes	430,602	477,196	10.82%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	17,207	20,523	19.27%
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51	**TOTAL MT Taxes Other Than Income**	469,503	526,304	12.10%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2019

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

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2019

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

Pension Costs

Year: 2019

1	Plan Name			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Project Unit Credit Method	IRS Code: 401b		
4	Annual Contribution by Employer: see line 20 below	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	61,918,782	67,561,782	9.11%
8	Service cost	365,422	516,179	41.26%
9	**Interest Cost**	2410069	2194498	-0.089446
10	Plan participants' contributions	-	-	
11	Amendments	-	-	
12	Actuarial Gain	7,481,941	(2,878,653)	-138.47%
13	Acquisition	118,612	(1,912,539)	-1712.43%
14	Benefits paid	(5,233,982)	(3,562,485)	31.94%
15	Benefit obligation at end of year	67,060,844	61,918,782	-7.67%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	54,663,690	59,883,968	9.55%
18	Actual return on plan assets	8,902,567	(1,884,387)	-121.17%
19	Acquisition	104,858	(1,568,406)	-1595.74%
20	Employer contribution	1,753,000	1,795,000	2.40%
21	Plan participants' contributions	-	-	
22	Benefits paid	(5,233,982)	(3,562,485)	31.94%
23	Fair value of plan assets at end of year	60,190,133	54,663,690	-9.18%
24	**Funded Status**	(6,870,711)	(7,255,092)	-5.59%
25	Unrecognized net actuarial loss	19,866,605	19,088,913	-3.91%
26	Unrecognized prior service cost		10,008	
27	Prepaid (accrued) benefit cost	12,995,894	11,843,829	-8.86%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	3.27%	4.40%	34.56%
31	Expected return on plan assets	5.25%	6.00%	14.29%
32	Rate of compensation increase	3.49%	3.52%	0.86%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	365,422	516,179	41.26%
36	Interest cost	2,410,069	2,194,498	-8.94%
37	Expected return on plan assets	(3,405,161)	(3,545,334)	-4.12%
38	Amortization of prior service cost	10,008	42,629	325.95%
39	Recognized net actuarial loss	1,220,597	2,063,399	69.05%
40	Net periodic benefit cost	600,935	1,271,371	111.57%
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	378	431	14.02%
48	Not Covered by the Plan			
49	Active	135	144	6.67%
50	Retired	182	221	21.43%
51	Deferred Vested Terminated	61	66	8.20%

Other Post Employment Benefits (OPEBS)

Year: 2019

	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	3.15%	4.28%	35.87%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	4.92%	4.94%	0.41%
10	Actuarial Cost Method			
11	Rate of compensation increase			
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	**TOTAL COMPANY**			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	5,054,827	5,969,597	18.10%
20	Service cost	148,394	193,017	30.07%
21	Interest Cost	185,532	178,719	-3.67%
22	Plan participants' contributions	95,778	120,493	25.80%
23	Amendments			
24	Actuarial Gain	507,154	(889,338)	-275.36%
25	Acquisition	(76,831)	(129,258)	-68.24%
26	Benefits paid	(738,554)	(388,403)	47.41%
27	Benefit obligation at end of year	5,176,300	5,054,827	-2.35%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year			
30	Actual return on plan assets			
31	Acquisition			
32	Employer contribution	642,776	267,910	-58.32%
33	Plan participants' contributions	95,778	120,493	25.80%
34	Benefits paid	(738,554)	(388,403)	47.41%
35	Fair value of plan assets at end of year			
36	**Funded Status**	(5,176,300)	(5,054,827)	2.35%
37	Unrecognized net actuarial loss			
38	Unrecognized prior service cost			
39	Prepaid (accrued) benefit cost	(5,176,300)	(5,054,827)	2.35%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	148,394	193,017	30.07%
42	Interest cost	185,532	178,719	-3.67%
43	Expected return on plan assets	-	-	
44	Amortization of prior service cost	(335,739)	(335,739)	
45	Recognized net actuarial loss			
46	Net periodic benefit cost	(1,813)	35,997	2085.49%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			
49	Amount Funded through 401(h)			
50	Amount Funded through Other ________________			
51	TOTAL	-	-	
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ____________			
55	TOTAL	-	-	

Other Post Employment Benefits (OPEBS) Continued

Year: 2019

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	313	324	3.51%
3	Not Covered by the Plan			
4	Active	206	223	8.25%
5	Retired	79	75	-5.06%
6	Spouses/Dependants covered by the Plan	28	68	142.86%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	-	-	
10	Service cost			
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year	-	-	
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	-	-	
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions	-	-	
24	Benefits paid	-	-	
25	Fair value of plan assets at end of year	-	-	
26	**Funded Status**	-	-	
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost	-	-	
30	**Components of Net Periodic Benefit Costs**			
31	Service cost	-	-	
32	Interest cost	-	-	
33	Expected return on plan assets	-	-	
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost	-	-	
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ___________________			
41	TOTAL	-	-	
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL	-	-	
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 17

Year: 2019

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	Linden R. Evans President and Chief Executive Office						
2	Richard W. Kinzley Sr. Vice President and Chief Financial Officer						
3	Brian G. Iverson Sr. Vice President and General Counsel						
4	Scott A. Buchholz Sr. Vice President and Chief Information Officer						
5	Stuart Wevik Sr. Vice President Utility Operations						

*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, 2019, 2018 and 2017. We have no employment agreements with our Named Executive Officers.

Name and Principal Position	Year	Salary	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(1)	2019	$1,220,000	$—	$—	$4,123,060	$112,009	$5,455,069
Executive Chairman	2018	$820,000	$1,943,679	$1,196,503	$523,260	$140,256	$4,623,698
	2017	$812,000	$1,942,843	$560,232	$2,155,930	$92,930	$5,563,935
Linden R. Evans(1)	2019	$713,333	$1,541,811	$800,400	$110,158	$473,600	$3,639,302
President and Chief Executive Officer	2018	$530,000	$859,369	$492,132	$—	$306,330	$2,187,831
	2017	$523,333	$818,045	$230,428	$59,631	$385,948	$2,017,385
Richard W. Kinzley	2019	$413,500	$524,220	$291,346	$68,631	$254,366	$1,552,063
Sr. Vice President and Chief Financial Officer	2018	$381,000	$491,036	$303,238	$—	$195,249	$1,370,523
	2017	$378,000	$465,256	$141,983	$36,599	$250,572	$1,272,410
Brian G. Iverson	2019	$370,833	$400,825	$240,120	$31,927	$156,990	$1,200,695
Sr. Vice President and General Counsel	2018	$350,000	$383,678	$255,351	$—	$123,852	$1,112,881
	2017	$346,667	$357,856	$97,823	$17,736	$145,405	$965,487
Scott A. Buchholz	2019	$336,667	$246,720	$181,424	$756,325	$134,089	$1,655,225
Sr. Vice President and Chief Information Officer	2018	$320,000	$245,514	$212,240	$38,765	$111,285	$927,804
	2017	$317,500	$235,193	$99,376	$366,235	$133,407	$1,151,711

(1) Mr. Emery retired as our Chairman and Chief Executive Officer, effective December 31, 2018. He continues his full-time employment with the Company as Executive Chairman of the Board, through May 1, 2020. Mr. Evans was named President and Chief Executive Officer effective January 1, 2019. Previously, he was President and Chief Operating Officer.

(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 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019.

(3) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2019 awards on January 28, 2020 and the awards were paid on March 6, 2020.

(4) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective years. These benefits have been valued using the assumptions disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2019. Because these assumptions sometimes change between measurement dates, the change in value reflects not only the change in value due to additional benefits earned during the period and the passage of time but also reflects the change in value caused by changes in the underlying actuarial assumptions. This has created significant volatility in the last three years with a large increase in 2019 and a large decrease in 2018, primarily related to the change in discount rates used to calculate the present value of these benefits. A value of zero is shown in the Summary Compensation Table for certain officers in 2018 because the SEC does not allow a negative number to be disclosed in the table.

BALANCE SHEET

Year: 2019

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	1,292,737,577	1,299,035,331	0%
4	101.1	Property Under Capital Leases		16,538,594	-100%
5	102	Electric Plant Purchased or Sold			
6	104	Electric Plant Leased to Others			
7	105	Electric Plant Held for Future Use	1,266,452	1,266,452	
8	106	Completed Constr. Not Classified - Electric	56,960,606	149,462,572	-62%
9	107	Construction Work in Progress - Electric	29,903,691	44,767,879	-33%
10	108	(Less) Accumulated Depreciation	(429,383,242)	(507,258,006)	15%
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.	(3,716,366)	(3,813,772)	3%
14	120	Nuclear Fuel (Net)			
15		**TOTAL Utility Plant**	952,639,026	1,004,869,358	-5%
16					
17	**Other Property & Investments**				
18	121	Nonutility Property			
19	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.			
20	123	Investments in Associated Companies			
21	123.1	Investments in Subsidiary Companies	100,633	1,029,017	-90%
22	124	Other Investments	4,787,904	4,050,353	18%
23	125	Sinking Funds			
24		**TOTAL Other Property & Investments**	4,888,537	5,079,370	-4%
25					
26	**Current & Accrued Assets**				
27	131	Cash	107,142	1,000	10614%
28	132-134	Special Deposits			
29	135	Working Funds	4,966	4,966	
30	136	Temporary Cash Investments			
31	141	Notes Receivable			
32	142	Customer Accounts Receivable	15,648,118	14,675,892	7%
33	143	Other Accounts Receivable	690,642	167,870	311%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(137,598)	(159,646)	14%
35	145	Notes Receivable - Associated Companies			
36	146	Accounts Receivable - Associated Companies	8,119,182	12,924,263	-37%
37	151	Fuel Stock	2,311,193	2,150,484	7%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals			
40	154	Plant Materials and Operating Supplies	20,891,945	23,867,961	-12%
41	155	Merchandise			
42	156	Other Material & Supplies			
43	157	Nuclear Materials Held for Sale			
44	163	Stores Expense Undistributed	1,246,859	1,778,004	-30%
45	165	Prepayments	3,149,219	3,160,241	0%
46	171	Interest & Dividends Receivable			
47	172	Rents Receivable			
48	173	Accrued Utility Revenues	12,332,877	10,913,572	13%
49	174	Miscellaneous Current & Accrued Assets	403,215	153,618	162%
50		**TOTAL Current & Accrued Assets**	64,767,760	69,638,225	-7%

Company Name: Black Hills Power d/b/a Black Hills Energy

BALANCE SHEET

Year: 2019

	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	2,733,676	2,597,171	5%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
8a	182.3	Other Regulatory Assets	74,353,149	74,609,205	
9	183	Prelim. Survey & Investigation Charges	6,058,812	124,309	4774%
10	184	Clearing Accounts	1,286,527	1,722,765	-25%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	3,670,417	4,191,046	-12%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	1,258,579	988,791	27%
16	190	Accumulated Deferred Income Taxes	30,244,823	34,673,387	-13%
17		**TOTAL Deferred Debits**	119,605,983	118,906,674	1%
18					
19		**TOTAL Assets & Other Debits**	1,141,901,306	1,198,493,627	-5%
		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	342,145,199	342,410,392	0%
35	217	(Less) Reacquired Capital Stock	(891,260)	(1,380,245)	35%
36		**TOTAL Proprietary Capital**	404,245,264	404,021,472	0%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	340,000,000	340,000,000	
41	222	(Less) Reacquired Bonds		-	
42	223	Advances from Associated Companies		-	
43	224	Other Long Term Debt	2,855,000	2,855,000	
44	225	Unamortized Premium on Long Term Debt		-	
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(86,250)	(82,110)	-5%
46		**TOTAL Long Term Debt**	342,768,750	342,772,890	0%

Company Name: Black Hills Power d/b/a Black Hills Energy

BALANCE SHEET

Year: 2019

	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		14,105,034	-100%
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	394,497	492,392	-20%
9	228.3	Accumulated Provision for Pensions & Benefits	14,606,182	14,635,914	0%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	2,523,526	3,162,087	-20%
12		**TOTAL Other Noncurrent Liabilities**	17,524,205	32,395,427	-46%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	24,315,680	19,817,584	23%
18	233	Notes Payable to Associated Companies	38,846,972	82,867,465	-53%
19	234	Accounts Payable to Associated Companies	25,803,650	32,120,834	-20%
20	235	Customer Deposits	1,874,819	2,254,967	-17%
21	236	Taxes Accrued	19,107,184	9,088,574	110%
22	237	Interest Accrued	4,626,830	4,652,426	-1%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	1,029,258	1,070,019	-4%
27	242	Miscellaneous Current & Accrued Liabilities	5,563,791	5,454,854	2%
28	243	Obligations Under Capital Leases - Current		293,388	-100%
29		**TOTAL Current & Accrued Liabilities**	121,168,184	157,620,111	-23%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,470,964	1,413,735	4%
34	253	Other Deferred Credits	2,146,051	2,621,658	-18%
35	255	Accumulated Deferred Investment Tax Credits	108,327,594	107,207,731	1%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	144,250,295	150,440,602	-4%
39		**TOTAL Deferred Credits**	256,194,904	261,683,726	-2%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		1,141,901,307	1,198,493,626	-5%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2019

	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: 2019

	Account Number & Title		Last Year	This Year	% Change
1					
2		Production Plant (cont.)			
3					
4	Other Production				
5					
6	340	Land & Land Rights			
7	341	Structures & Improvements			
8	342	Fuel Holders, Producers & Accessories			
9	343	Prime Movers			
10	344	Generators			
11	345	Accessory Electric Equipment			
12	346	Miscellaneous Power Plant Equipment			
13					
14		**TOTAL Other Production Plant**			
15					
16		**TOTAL Production Plant**			
17					
18		**Transmission Plant**			
19					
20	350	Land & Land Rights			
21	352	Structures & Improvements			
22	353	Station Equipment			
23	354	Towers & Fixtures			
24	355	Poles & Fixtures			
25	356	Overhead Conductors & Devices			
26	357	Underground Conduit			
27	358	Underground Conductors & Devices			
28	359	Roads & Trails			
29					
30		**TOTAL Transmission Plant**			
31					
32		**Distribution Plant**			
33					
34	360	Land & Land Rights	26,304	26,304	
35	361	Structures & Improvements	(4,805)	(4,805)	
36	362	Station Equipment	(433,639)	(390,188)	-11%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	450,185	520,469	-14%
39	365	Overhead Conductors & Devices	485,273	491,427	-1%
40	366	Underground Conduit	226	(1,326)	117%
41	367	Underground Conductors & Devices	13,144	13,144	
42	368	Line Transformers	89,584	83,017	8%
43	369	Services	8,109	8,109	
44	370	Meters	856	(2,243)	138%
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	635,237	743,908	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2019

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment	425	425	
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	425	425	
17				
18	**TOTAL Electric Plant in Service**	635,662	744,333	

MONTANA DEPRECIATION SUMMARY

Year: 2019

	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	743,908	986,851	1,011,001	
8	General	425	127	150	
9	**TOTAL**	744,333	986,978	1,011,151	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

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

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent	% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number 83.4.25			
2	Order Number 4998			
3				
4	Common Equity	52.83%	15.00%	7.92%
5	Preferred Stock	11.96%	9.03%	1.08%
6	Long Term Debt	35.21%	7.75%	2.73%
7	Other			
8	**TOTAL**	100.00%		11.73%
9				
10	Actual at Year End			
11				
12	Common Equity	53.49%		
13	Preferred Stock			
14	Long Term Debt	46.51%		
15	Other			
16	**TOTAL**	100.00%		

STATEMENT OF CASH FLOWS

Year: 2019

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	45,644,951	46,901,602	-3%
6	Depreciation	39,670,744	39,299,264	1%
7	Amortization		2,082,887	-100%
8	Deferred Income Taxes - Net	5,214,661	5,819,803	-10%
9	Investment Tax Credit Adjustments - Net			
10	Change in Operating Receivables - Net	(2,360,277)	1,189,700	-298%
11	Change in Materials, Supplies & Inventories - Net	(1,409,773)	(3,346,452)	58%
12	Change in Operating Payables & Accrued Liabilities - Net	(5,767,494)	(10,628,117)	46%
13	Allowance for Funds Used During Construction (AFUDC)	(220,749)	1,457	-15251%
14	Change in Other Assets & Liabilities - Net	(597,925)	(3,290,198)	82%
15	Other Operating Activities (explained on attached page)	4,524,627	(292,023)	1649%
16	**Net Cash Provided by/(Used in) Operating Activities**	84,698,765	77,737,923	9%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(74,021,987)	(124,461,017)	41%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets	(4,867,018)		#DIV/0!
22	Proceeds from Disposal of Noncurrent Assets	4,993,727	1,038,120	381%
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)		1,683,357	-100%
27	**Net Cash Provided by/(Used in) Investing Activities**	(73,895,278)	(121,739,540)	39%
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			
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)	(10,707,199)	43,895,475	-124%
46	**Net Cash Provided by (Used in) Financing Activities**	(10,707,199)	43,895,475	-124%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	96,288	(106,142)	191%
49	**Cash and Cash Equivalents at Beginning of Year**	15,820	112,108	-86%
50	**Cash and Cash Equivalents at End of Year**	112,108	5,966	1779%

Attachment 23A

Footnotes for Statement of Cash Flow — Year: 2019

Line 8, current year - Deferred Income Taxes - Net

$	(4,281,026)	Deferred Income Taxes (Net)
$	608,531	Uncollectible accounts
$	474,763	Amortization of deferred financing costs
$	5,417,267	Preliminary survey expenses related to abandoned project
$	778,298	Benefit plan expense
$	2,821,970	Amortization of regulatory assets and liabilities
$	5,819,803	Total

`

Line 15, current year- Other Operating Activities consists of:

$	(1,753,000)	Benefit plan contribution
$	103,998	Other changes in current and non-current assets
$	1,356,979	Other changes in current and non-current liabilities
$	(292,023)	Total

Line 15, last year - Other Operating Activities consists of:

$	516,982	Bad debt expense
$	415,234	Deferred financing costs
$	1,517,841	Benefit plan expense
$	(1,795,000)	Benefit plan contribution
$	3,296,355	Change in regulatory assets and liabilities
$	(921,894)	Other changes in current and non-current assets
$	1,480,510	Other changes in current and non-current liabilities
$	64,332	Other comprehensive income
$	(49,733)	Gain on retirement of assets
$	4,524,627	Total

Line 19, current year - Construction/Acquisition of Property, Plant, and Equipment

$	(122,833,414)	Construction and Acquisition of Plant (Including Land)
$	(1,436,770)	(Less) Allowance for Other Funds Used During Construction
$	(190,833)	Other: 123.1, 124, 128
$	(124,461,017)	Total

Line 45, current year-Other Financing Activities consist of:

$	25,000,000	Notes payable to Parent
$	18,895,475	Net borrowings from Money Pool
$	43,895,475	Total

Line 45, last year - Other Financing Activities consist of:

$	(10,707,199)	Payments to Money Pool

Company Name: Black Hills Power d/b/a Black Hills Energy SCHEDULE 24

LONG TERM DEBT

Year: 2019

	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 AG	10/14	10/44	85,000,000	85,000,000	85,000,000	4.430%	3,789,394	4.46%
2									
3	Series AE	08/02	08/32	75,000,000	75,000,000	75,000,000	7.230%	5,519,913	7.36%
4									
5	Series AF	10/09	11/39	180,000,000	180,000,000	180,000,000	6.125%	11,105,056	6.17%
6									
7	1994 A Environmental								
8	Improvement Bonds	06/94	06/24	2,855,000	2,855,000	2,855,000	1.64%	46,793	1.64%
9									
10	Series Y	6/15/1988	6/15/2018	6,000,000	6,000,000		n/a	11,109	
11	Series Z	5/29/1991	5/29/2021	35,000,000	35,000,000		n/a	84,828	
12	Series AB	9/1/1999	9/1/2024	45,000,000	45,000,000		n/a	116,828	
13	Series 2004 Campbell County	38261	45566	12,200,000	12,200,000		n/a	68,121	
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			441,055,000	441,055,000	342,855,000		20,742,044	6.05%

Company Name: Black Hills Power d/b/a Black Hills Energy SCHEDULE 25

PREFERRED STOCK

Year: 2019

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

Company Name: Black Hills Power d/b/a Black Hills Energy

COMMON STOCK

Year: 2019

		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									
2									
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: 2019

	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				
31	Note: This schedule is not completed because			
32	Montana revenues represents less than			
33	2.53% of the Company's revenue.			
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: 2019

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	744
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	(1,011)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	(267)
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	8,705
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	8,705
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	8,705
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	24
37		Industrial	7
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	44
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	118,200
45		Average Annual Residential Cost per (Kwh) (Cents) *	$ 0.0676
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	$ 51.25
48		Gross Plant per Customer	(6.07)

Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 29

MONTANA CUSTOMER INFORMATION

Year: 2019

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties	2,903	13	24	7	44
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**	2,903	13	24	7	44

Company Name: Black Hills Power d/b/a Black Hills Energy SCHEDULE 30

MONTANA EMPLOYEE COUNTS

Year: 2019

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2020

	Project Description	Total Company	Total Montana
1	Distribution - Belle Creek DVAR IGBT repl		160,000
2	Distribution - 69kV Belle Creek Cap Bank CTs		150,000
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
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42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**		310,000

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2019

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	29	1900	368	289,252	43,797
2	Feb.	225	2000	406	270,164	24,907
3	Mar.	3	2000	381	273,608	30,868
4	Apr.	30	900	321	232,047	22,473
5	May	21	1800	322	256,863	43,038
6	Jun.	28	1700	376	258,048	47,503
7	Jul.	31	1600	420	282,041	37,320
8	Aug.	6	1600	416	287,617	46,847
9	Sep.	4	1700	390	258,748	45,266
10	Oct.	30	800	368	271,261	74,004
11	Nov.	6	1800	364	276,206	5,059
12	Dec.	9	800	347	284,322	51,194
13	**TOTAL**				3,240,177	472,276

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.					
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		Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,809,404
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other		for Resale	164,213
7	(Less) Energy for Pumping			
8	**NET Generation**		Non-Requirements Sales	
9	Purchases		for Resale	1,163,223
10	Power Exchanges			
11	Received		Energy Furnished	
12	Delivered		Without Charge	
13	**NET Exchanges**			
14	Transmission Wheeling for Others		Energy Used Within	
15	Received		Electric Utility	109,737
16	Delivered			
17	**NET Transmission Wheeling**		Total Energy Losses	(6,400)
18	Transmission by Others Losses			
19	**TOTAL**		**TOTAL**	3,240,177

SOURCES OF ELECTRIC SUPPLY

Year: 2019

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	7,894
2					
3	Thermal	Ben French	Rapid City, SD	10	(323)
4					
5	Thermal	Wyodak	Gillette, WY	69	434,918
6					
7	Thermal	Neil Simpson II	Gillette, WY	84	664,557
8					
9	Thermal	Lange	Rapid City, SD	39	22,324
10					
11	Thermal	Neil Simpson CT	Gillette, WY	39	50,296
12					
13	Thermal	Wygen III	Gillette, WY	57	397,163
14					
15	Combined Cycle	Cheyenne Prairie	Cheyenne, WY	60	104,346
16					
17	Purchase	See Schedule 32			
18					
19	Wheeling	See Schedule 32			
20					
21	Total Interchange	See Schedule 32			
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			456	1681175

Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2019

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

Company Name: Schedule 35a

Electric Universal System Benefits Programs

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

Company Name: Schedule 35b

Montana Conservation & Demand Side Management Programs

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

MONTANA CONSUMPTION AND REVENUES

Year: 2019

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$7,995	$7,277	118	105	13	13
2	Commercial - Small	19,249	19,176	163	169	24	24
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	9279330	8149045	136739	116655	7	8
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**	$9,306,574	$8,175,498	137,020	116,929	44	45

NOTES TO FINANCIAL STATEMENTS
December 31, 2019 and 2018

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc., doing business as Black Hills Energy ("South Dakota Electric,", the "Company," “we,” “us” or “our”) is a regulated electric utility serving customers in Montana, South Dakota and Wyoming. We are a wholly-owned subsidiary of Black Hills Corporation ("BHC" or "Parent"), a public registrant listed on the New York Stock Exchange.

Basis of Presentation

The financial statements include the accounts of Black Hills Power, Inc. and also our ownership interests in the assets, liabilities and expenses of our jointly owned facilities (Note 4).

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). Additionally, these requirements differ from GAAP related to the presentation of certain items discussed below.

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Deferred financing costs are presented in deferred debits on the balance sheet for FERC reporting. For GAAP reporting, these are presented net within long-term debt.
- Unbilled revenue is presented in Accrued Utility Revenues for FERC reporting and presented in Accounts Receivable for GAAP reporting.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Certain commodity trading purchases and sales transactions are presented gross as expense and revenues for the FERC presentation; however, the net margin is reported as net sales for the GAAP presentation.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expense for the GAAP presentation.
- Only the service cost component of net periodic pension and post-retirement benefit costs can be capitalized for GAAP

reporting. However, all cost components of net periodic pension and post-retirement benefit costs are eligible for capitalization under FERC regulations.

- Capital and operating leases are both classified as capital leases on the balance sheet for FERC reporting. For GAAP reporting, these are presented as other current and noncurrent assets and liabilities.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with FERC 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. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. For purposes of the cash flow statements, we consider all highly liquid investments with original maturities of three months or less at the time of purchase to be cash and cash equivalents. As of December 31, 2019 and 2018, we have no cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable consists 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.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

Changes to allowance for doubtful accounts for the years ended December 31, were as follows (in thousands):

Description	Balance at beginning of year	Additions charged to costs and expenses	Deductions charged to costs and expenses	Balance at end of year
		(in thousands)		
Allowance for doubtful accounts (Account 144):				
2019	$ 138	$ 899	$ (877)	$ 160
2018	$ 224	$ 911	$ (997)	$ 138

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are recorded using the weighted-average cost method.

Deferred Financing Costs

Deferred financing costs include loan origination fees, underwriter fees, legal fees and other costs directly attributable to the issuance of debt. Deferred financing costs are amortized over the estimated useful life of the related debt. Deferred financing costs are presented on the balance sheet within Deferred Debits - Unamortized Debt Expenses (181).

Regulatory Accounting

Our regulated electric operations are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. We account for income and expense items in accordance with accounting standards for regulated operations:

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.

- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred

Management continually assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders, and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

If changes in the regulatory environment occur, we may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from our balance sheet. Such changes could adversely affect our results of operations, financial position or cash flows.

As of December 31, 2019 and 2018, we had total regulatory assets of $75 million and $74 million respectively, and total regulatory liabilities of $107 million and $108 million respectively. See Note 7 for further information.

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Balance Sheets.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. At the time of such retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary. No impairment loss was recorded during the years ended December 31, 2019 and 2018.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.2% in 2019 and 2.3% in 2018.

Derivatives and Hedging Activities

Derivatives are measured at fair value and recognized as either assets or liabilities on the Balance Sheets, except for derivative contracts that qualify for and are elected under the normal purchase and normal sales exception. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. Normal purchase and sales contracts are recognized when the underlying physical transaction is completed under the accrual basis of accounting. As part of our operations, we enter into contracts to buy and sell energy to meet the requirements of our customers.

From time to time we utilize risk management contracts including interest rate swaps to fix the interest on variable rate debt, or to lock in the Treasury yield component associated with anticipated issuance of senior notes. For swaps that settled in connection with the issuance of senior debt, the effective portion is deferred as a component in Accumulated Other Comprehensive Income (AOCI) and recognized as interest expense over the life of the senior note. As of December 31, 2019, we have no outstanding interest rate swap agreements.

Revenues and expenses on contracts that qualify as derivatives may be elected to be accounted for under the normal purchases and normal sales exception and are recognized when the underlying physical transaction is completed under the accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it was determined that a transaction designated as a normal purchase or normal sale no longer met the exception, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

Fair Value Measurements

We use the following fair value hierarchy for determining inputs for our financial instruments. Our assets and liabilities for financial instruments are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. Level 1 instruments primarily consist of highly liquid and actively traded financial instruments with quoted pricing information on an ongoing basis.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets other than quoted prices in Level 1, 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 are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

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 the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable, such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs. We currently do not have any Level 3 investments.

Additional information is included in Note 6.

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.

The Company uses the asset and liability method in accounting for income taxes. Under the asset and 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 use the deferral method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

We recognize interest income or interest expense and penalties related to income tax matters in Other interest expense on the Statements of Income.

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified within deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheets. See Note 9 for additional information.

Recently Adopted Accounting Standards

Leases, ASU 2016-02

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, to increase transparency and comparability among organizations by requiring the recognition of right-of-use assets and lease liabilities on the balance sheet for most leases, whereas previously only financing-type lease liabilities (capital leases) were recognized on the balance sheet. Under the new standard, disclosures are required to meet the objective of enabling users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases.

We adopted the standard effective January 1, 2019. We elected not to recast comparative periods coinciding with the new lease standard transition and will report these comparative periods as presented under previous lease guidance. In addition, we elected the package of practical expedients permitted under the transition guidance with the new standard, which among other things, allowed us to carry forward the historical lease classification. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for existing land easements agreements.

Adoption of the new standard resulted in the recording of a $16.3 million operating lease right-of-use asset (account 101.1), $1.9 million of corresponding amortization (account 108.2), and a $14.4 million off-setting operating lease obligation liability (accounts 227 and 243) as of January 1, 2019. The cumulative effect of the adoption did not materially impact results of operations. Adoption of the new standard had no impact on cash flows, rate base or cost of service rates.

See Note 8 for additional details on leases.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, ASU 2018-02

In February 2018, the FASB issued ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* This ASU was issued to address industry concerns regarding the application of current accounting guidance to certain provisions of the new tax reform legislation. This ASU permits entities to make a one-time reclassification from AOCI to retained earnings for stranded tax effects resulting from the newly enacted corporate tax rate. The amount of the reclassification is calculated on the basis of the difference between the historical and newly enacted tax rates for deferred tax liabilities and assets related to items within AOCI. The ASU is effective for fiscal years beginning after December 15, 2018, including interim periods therein, and early adoption is permitted. We have implemented this ASU, which resulted in a reclassification of $0.3 million of stranded tax effects from AOCI to retained earnings. Adoption of this ASU did not impact our financial position, results of operations or cash flows.

(2) REVENUE

Our revenue contracts generally provide for performance obligations that are fulfilled and transfer control to customers over time, represent a series of distinct services that are substantially the same, involve the same pattern of transfer to the customer, and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice. Our primary types of revenue contracts are:

- Regulated electric utility services tariffs - Our regulated operations, as defined by ASC 980, provide services to regulated customers under tariff rates, charges, terms and conditions of service, and prices determined by the jurisdictional regulators designated for our service territories. Our regulated services primarily encompass single performance obligations for delivery of commodity electricity and electric transmission services. These service revenues are variable based on quantities delivered, influenced by seasonal business and weather patterns. Tariffs are only permitted to be changed through a rate-setting process involving the state or federal regulatory commissions to establish contractual rates between the utility and its customers. All of our regulated utility sales are subject to regulatory-approved tariffs.

- Power sales agreements - We have long-term wholesale power sales agreements with other load serving entities for the sale of excess power from owned generating units. In addition to these long-term contracts, the Company also sells excess energy to other load-serving entities on a short-term basis. The pricing for all of these arrangements is included in the executed contracts or confirmations, reflecting the standalone selling price, and is variable based on energy delivered.

The following table depicts the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition. Sales tax and other similar taxes are excluded from revenues.

		Year ended December 31,	
		2019	2018
		(in thousands)	
Customer types:			
Retail	$	202,569	197,184
Wholesale		30,899	33,687
Market - off-system sales		16,475	17,691

Transmission/Other		50,329	49,015
Revenue from contracts with customers		300,272	297,577
Other revenues		2,767	503
Total revenues	$	303,039	298,080
Timing of revenue recognition:			
Services transferred over time	$	300,272	297,577
Revenue from contracts with customers	$	300,272	297,577

The majority of our revenue contracts are based on variable quantities delivered; any fixed consideration contracts with an expected duration of one year or more are immaterial to our revenues. Variable consideration constraints in the form of discounts, rebates, credits, price concessions, incentives, performance bonuses, penalties or other similar items are not material for our revenue contracts. We are the principal in our revenue contracts, as we have control over the services prior to those services being transferred to the customer.

Revenue Not in Scope of ASC 606

Other revenues included in the table above include revenue accounted for under separate accounting guidance, including alternative revenue programs revenue under ASC 980.

Significant Judgments and Estimates

Unbilled Revenue

To the extent that deliveries have occurred but a bill has not been issued, the Company accrues an estimate of the revenue since the latest billing. This estimate is calculated based on 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 Accrued Utility Revenues on the accompanying Balance Sheets.

Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable and is further discussed in Note 1. We do not typically incur costs that would be capitalized, to obtain or fulfill a contract.

(3) PROPERTY PLANT AND EQUIPMENT

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

	2019	2019 Weighted Average Useful Life (in years)	2018	2018 Weighted Average Useful Life (in years)
Electric plant:				
Production	617,250	46	593,259	46
Transmission	235,390	51	208,610	48
Distribution	431,783	46	394,475	45

Plant acquisition adjustment [(a)]	4,870	32	4,870	32
General	165,341	29	154,621	28
Operating lease assets [(b)]	16,539		—	
Total plant-in-service	1,471,173		1,355,835	
Construction work in progress	44,768		29,904	
Total electric plant	1,515,941		1,385,739	
Less accumulated depreciation and amortization	(464,309)		(433,068)	
Electric plant net of accumulated depreciation and amortization	1,051,632		952,671	

(a) The plant acquisition adjustment is included in rate base and is being recovered with 11 years remaining.

(b) These relate to our adoption of ASU 2016-02, Leases (*Topic 842)* and are not included in rate base. See Notes 1 and 8 for additional information concerning ASC 842 adoption and lease assets disclosures.

(4) JOINTLY OWNED FACILITIES

Our financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities' expenses are reflected in the appropriate categories of operating expenses in the Statements of Income (Loss). Each owner of the facility is responsible for financing its investment in the jointly-owned 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, including 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.

- We own 55 MW of Cheyenne Prairie, a 95 MW gas-fired power generation facility located in Cheyenne, Wyoming. Wyoming Electric owns the remaining 40 MW. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

As of December 31, 2019, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

Interest in jointly-owned facilities	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 116,074	$ 729	$ (64,413)

Transmission Tie	$	19,862	$	4,161	$	(6,612)
Wygen III	$	146,161	$	400	$	(25,518)
Cheyenne Prairie	$	92,684	$	532	$	(14,202)

(5) LONG-TERM DEBT

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

		Interest Rate at	Balance Outstanding	
	Due Date	December 31, 2019	December 31, 2019	December 31, 2018
First Mortgage Bonds due 2032	August 15, 2032	7.23%	$ 75,000	$ 75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Less unamortized debt discount			(82)	(86)
Series 94A Debt [(a)]	June 1, 2024	1.84%	2,855	2,855
Total Long-term Debt			$ 342,773	$ 342,769

(a) Variable interest rate at December 31, 2019.

Net deferred financing costs of approximately $2.6 million and $2.7 million were recorded on the accompanying Balance Sheets in Deferred Debits - Unamortized Debt Expenses (181) at December 31, 2019 and 2018, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.1 million for both of the years ended December 31, 2019 and 2018 are included in Interest Charges - Amort. of Debt Disc. And Expense (428) 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, 2019.

Long-term Debt Maturities

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

2020	$	—
2021	$	—
2022	$	—
2023	$	—
2024	$	2,855
Thereafter	$	340,000

(6) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2019		2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash [(a)]	$ 6	$ 6	$ 112	$ 112
Notes payable to Parent [(b)]	$ 25,000	$ 25,000	$ —	$ —
Long-term debt [(c)]	$ 342,773	$ 412,894	$ 342,769	$ 412,894

(a) The cash fair value approximates carrying value and therefore is classified as Level 1 in the fair value hierarchy. We believe that the market risk arising from cash in a bank account is minimal.

(b) Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.

(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

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

Notes Payable to Parent

For additional information on our notes payable to parent, see Note 14.

Long-Term Debt

For additional information on our long-term debt, see Note 4.

(7) REGULATORY MATTERS

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

	2019	2018
Regulatory assets:		
Deferred taxes on AFUDC [(b)]	4,928	5,020
Employee benefit plans [(c)]	20,562	19,748
Deferred energy and fuel cost adjustments [(a)]	23,202	20,334
Deferred taxes on flow through accounting [(a)]	9,801	8,749
Decommissioning costs [(b)]	6,211	8,196
Vegetation management [(a)]	8,062	10,366
Other regulatory assets [(a)]	1,843	1,940
Total Other Regulatory Assets (182.3)	74,609	74,353
Regulatory liabilities:		
Employee benefit plans and related deferred taxes [(c)]	7,022	7,518
Excess deferred income taxes [(c)]	99,745	100,276
Other regulatory liabilities [(c)]	441	534

Total Other Regulatory Liabilities (254)	107,208	108,328

(a) Recovery of costs but we are 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 or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base

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

Deferred Taxes on 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 plan and other post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income. In addition, this regulatory asset 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.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our customers that is 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. We file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by the applicable state utility commissions.

Deferred Taxes on 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. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered currently deductible for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - We received approval in 2014 for regulatory treatment on the remaining net book values and decommissioning costs of our decommissioned coal plants.

Vegetation Management Costs - We received approval in 2013 for regulatory treatment on vegetation management maintenance costs for our distribution system rights-of-way.

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

Employee Benefit Plans **-** Employee benefit plans represent the cumulative excess of pension and other postretirement benefit 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.

Excess Deferred Income Taxes - The revaluation of our deferred tax assets and liabilities due to the passage of the TCJA is recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA. See Note 9 for additional information.

Regulatory Matters

Settlement

On January 7, 2020, South Dakota Electric received approval from the South Dakota Public Utilities Commission on a settlement agreement to extend the 6-year moratorium period by an additional 3 years to June 30, 2026. Also, as part of the settlement, we withdrew our application for deferred accounting treatment and expensed $5.4 million of development costs related to projects we no longer intend to construct. This settlement amends a previous agreement approved by the SDPUC on June 16, 2017, whereby South Dakota Electric would not increase base rates, absent an extraordinary event, for a 6-year moratorium period effective July 1, 2017. The moratorium period also includes suspension of both the Transmission Facility Adjustment and Environmental Improvement Adjustment.

Renewable Ready

In July 2019, South Dakota Electric and Wyoming Electric received approvals for the Renewable Ready program and related jointly-filed CPCN to construct Corriedale. The wind project will be jointly owned by the two electric utilities to deliver renewable energy for large commercial, industrial and governmental agency customers. In November 2019, South Dakota Electric received approval from the SDPUC to increase the offering under the program by 12.5 MW to 32.5 MW. The two electric utilities also received a determination from the WPSC that the wind project can be increased to 52.5 MW. The $79 million project is expected to be in service by year-end 2020.

FERC Formula Rate

The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2019 the annual revenue requirement increased by $1.9 million and included estimated weighted average capital additions of $31 million for 2018 and 2019 combined. The annual transmission revenue requirement has a true up mechanism that is posted in June of each year.

(8) LEASES

We have a ground lease for the Wygen III generating facility with an affiliate and communication tower site and operation center facility leases with third parties. Our leases have remaining terms ranging from less than one year to 30 years.

The components of lease expense were as follows (in thousands):

	Income Statement Location	Twelve Months Ended December 31, 2019
Operating lease cost	Operating Expenses (401)	$ 908
Variable lease cost	Operating Expenses (401)	137
Total lease cost		$ 1,045

Supplemental balance sheet information related to leases was as follows (in thousands):

	Balance Sheet Location	As of December 31, 2019
Assets:		

Operating leases	Utility Plant (101-106, 114)	$	16,538
Operating leases	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)		(2,164)
Total lease assets		$	14,374
Liabilities:			
Operating leases	Obligations Under Capital Leases - Noncurrent (227)	$	14,105
Operating leases	Obligations Under Capital Leases - Current (243)	$	293
Total lease liabilities		$	14,398

Supplemental cash flow information related to leases was as follows (in thousands):

		Twelve Months Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	912
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$	—

	As of December 31, 2019
Weighted average remaining lease term (years):	
Operating leases	30 years
Weighted average discount rate:	
Operating leases	4.3%

Scheduled maturities of operating lease liabilities for future years were as follows (in thousands):

		Total
2020	$	912
2021		911
2022		911
2023		908
2024		906
Thereafter		21,128
Total lease payments	$	25,676
Less imputed interest		11,278
Present value of lease liabilities	$	14,398

As previously disclosed in Note 11 of the Notes to Financial Statements in our 2018 FERC Form 1, prior to the adoption of ASU 2016-02, *Leases (Topic 842),* the future minimum payments required under operating lease agreements as of December 31, 2018 were as follows (in thousands):

		Operating Leases
2019	$	911

2020		856
2021		855
2022		856
2023		853
Thereafter		21,947
Total lease payments	$	26,278

(9) INCOME TAXES

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

		2019		2018
Current	$	13,782	$	5,457
Deferred		(4,281)		5,215
Total income tax expense	$	9,501	$	10,672

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

		2019		2018
Deferred tax assets:				
Regulatory liabilities		25,623		25,587
Other		9,050		4,658
Total deferred tax assets		34,673		30,245
Deferred tax liabilities:				
Accelerated depreciation and other plant related differences		(128,708)		(125,594)
Regulatory assets		(7,193)		(7,147)
Deferred costs		(8,264)		(8,572)
Other		(6,276)		(2,937)
Total deferred tax liabilities		(150,441)		(144,250)
Net deferred tax assets (liabilities)	$	(115,768)	$	(114,005)

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

	2019	2018
Federal statutory rate	21.0 %	21.0 %
Amortization of excess deferred and investment tax credits	(3.0)%	(1.3)%
Flow through adjustments (a)	(1.5)%	(1.7)%
Tax reform (b)	— %	2.5 %
Other	0.3 %	(1.6)%
	16.8 %	18.9 %

(a) Flow-through adjustments related primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs. 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 tax expense.

(b) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21%, effective January 1, 2018. The 2017 effective tax rate reduction reflects the revaluation of deferred income taxes required by the change. During the year ended December 31, 2018, we recorded approximately $0.9 million of additional tax expense associated with changes in the prior estimated impacts of TCJA related items.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheet (in thousands):

	2019	2018
Unrecognized tax benefits at January 1	$ 249	$ 302
Additions for prior year tax positions	—	—
Additions for current year tax positions	—	2
Reductions for prior year tax positions	(33)	(55)
Unrecognized tax benefits at December 31	$ 216	$ 249

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is not material to the financial results of the Company.

It is the Company's continuing practice to recognize interest and/or penalties related to income tax matters in Other interest expense. During the years ended December 31, 2019 and 2018, the interest expense recognized was not material to the financial results of the Company.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statutes of limitations on or before December 31, 2020.

We file income tax returns in the United States federal jurisdictions as a member of the BHC consolidated group.

Tax Reform

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017.

The regulatory liability for excess deferred income taxes that is considered protected and unprotected as of December 31 is reflected below (in millions):

Jurisdiction	2019	2018
Protected		
FERC	$ 13.9	$ 15.5
State	71.0	67.8
Total protected	$ 84.9	$ 83.3
Unprotected		
FERC	$ 2.4	$ —

State	12.4	17.0
Total unprotected	$ 14.8	$ 17.0
Total	$ 99.7	$ 100.3

In 2018, we received an order from the South Dakota Public Utilities Commission approving a settlement stipulation regarding how customer rates should be reduced for excess deferred income taxes. The settlement stipulation required (i) a refund of protected and non-protected plant asset related excess deferred income taxes pursuant to the average rate assumption method ("ARAM") and (ii) a refund in 2019 of all non-protected excess deferred income taxes not related to plant assets. The 2018 reduction in the excess deferred income tax regulatory liability associated with ARAM was offset against account 411, the account to which the original remeasurement of deferred income taxes was recorded in December 2017. The balance of the adjustments to the regulatory liability for net excess deferred taxes recorded in 2018 all reflected changes in estimates, not amortizations.

The adjustments to the regulatory liability (account 254) for the year ended December 31, 2019, the estimated amortization period based on regulatory orders, and the accounts where the adjustments and amortization were reported are reflected below (in millions):

Jurisdiction	December 31, 2018	Accounts							December 31, 2019	Amortization Period
		190	236	254 Other (c)	282	283	411 Amort.	409-411		
Protected										
FERC	$ 15.5	$ —	$ —	$ (1.6)	$ —	$ —	$ —	$ —	$ 13.9	(a)
State	67.8	(0.1)	—	3.1	—	—	0.2	—	71.0	(a)
Total protected	$ 83.3	$ (0.1)	$ —	$ 1.5	$ —	$ —	$ 0.2	$ —	$ 84.9	
Unprotected										
FERC	—	$ (0.1)	$ —	$ 2.8	$ —	$ —	$ (0.3)	$ —	$ 2.4	(b)
State	17.0	(0.3)	—	(2.8)	—	—	(1.5)	—	12.4	(b)
Total unprotected	$ 17.0	$ (0.4)	$ —	$ —	$ —	$ —	$ (1.8)	$ —	$ 14.8	
Total	$ 100.3	$ (0.5)	$ —	$ 1.5	$ —	$ —	$ (1.6)	$ —	$ 99.7	

(a) The weighted average amortization period was estimated at 45 years under ARAM.

(b) The weighted average amortization period was estimated at 45 years under ARAM for plant-related unprotected and 1 year for non-plant unprotected.

(c) Current year adjustments to account 254 include allocated Black Hills Service Company (BHSC) excess deferred income tax liabilities to South Dakota Electric. Certain property that benefits South Dakota Electric is allocated from BHSC to us. Historically, the deferred income taxes related to that property were not allocated. Effective 2019, BHSC started allocating those deferred taxes to South Dakota Electric. The prior years amounts were not considered material and as a result, we did not revise. The BHSC allocations are reflected as Protected current year activity in the rollforward in FERC and State jurisdictions of $0.2 million and $1.3 million, respectively.

The FERC has not yet issued an order regarding how customer rates should be reduced for excess deferred income taxes.

(10) COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

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

	Location on the Statement of Income	Amounts Reclassified from AOCI	
		2019	2018
Gains and Losses on cash flow hedges:			
Interest rate swaps gain (loss)	Interest charges	(64)	(64)
Income tax	Income tax benefit (expense)	132	13
Total reclassification adjustments related to cash flow hedges, net of tax		68	(51)
Amortization of defined benefit plans:			
Actuarial gain (loss)	Operating expenses	(65)	(103)
Income tax	Income tax benefit (expense)	166	22
Total reclassification adjustments related to defined benefit plans, net of tax		101	(81)

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):

	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2018	$ (500)	$ (391)	$ (891)
Other comprehensive income (loss) before reclassifications	—	(320)	(320)
Amounts reclassified from AOCI	(68)	(101)	(169)
As of December 31, 2019	$ (568)	$ (812)	$ (1,380)

	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2017	$ (551)	$ (707)	$ (1,258)
Other comprehensive income (loss) before reclassifications	—	235	235
Amounts reclassified from AOCI	51	81	132
As of December 31, 2018	$ (500)	$ (391)	$ (891)

(11) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2019	2018
	(in thousands)	
Non-cash investing and financing activities -		
Accrued property, plant and equipment purchases at December 31	$ 12,305	$ 15,180
Non-cash decrease to money pool note receivable, net	$ —	$ (36,000)
Non-cash dividend to Parent	$ —	$ 36,000
Cash (paid) refunded during the period for -		
Interest (net of amounts capitalized)	$ (21,909)	$ (21,988)
Income taxes (paid), net	$ (24,372)	$ (10,394)

(12) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

BHC sponsors a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation to the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plan provides a Company matching contribution for all eligible participants. Certain eligible participants who are not currently accruing a benefit in the Pension Plan also receive a Company retirement contribution based on the participant's age and years of service. Vesting of all Company and matching contributions occurs at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

Defined Benefit Pension Plan (Pension Plan)

We have a defined benefit pension plan ("Pension Plan") covering certain eligible employees. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan has been closed to new employees and certain employees who did not meet age and service based criteria.

The Pension Plan assets are held in a Master Trust. Our Board of Directors has approved the Pension Plan's 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 Pension Plan's beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan's benefit payment obligations. The Pension Plan's assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns, and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target allocation range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2019, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 29% to 37% return-seeking assets and 63% to 71% liability-hedging assets.

Our Pension Plan is funded in compliance with the federal government's funding requirements.

Pension Plan Assets

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

	2019	2018
Equity securities	20%	17%
Real estate	3%	4%
Fixed income funds	71%	71%
Cash and cash equivalents	2%	3%
Hedge funds	4%	5%
Total	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

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 Plans

BHC sponsors retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations.
Pre-65 retirees receive their retiree medical benefits through the Black Hills self-insured retiree medical plans. Healthcare coverage for Medicare-eligible BHP retirees is provided through an individual market healthcare exchange.

Plan Assets

We fund our Healthcare Plans on a cash basis as benefits are paid.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare benefits include company and participant paid premiums.

Contributions for the years ended December 31 were as follows (in thousands):

	2019	2018
Defined Contribution Plans		
Company Retirement Contribution	$ 888	$ 876
Matching Contributions	$ 1,275	$ 1,272

Defined Benefit Plans			
Defined Benefit Pension Plan	$	1,753 $	1,795
Non-Pension Defined Benefit Postretirement Healthcare Plans	$	739 $	388
Supplemental Non-qualified Defined Benefit Plan	$	266 $	238

While we do not have required contributions, we expect to make approximately $1.7 million in contributions to our Defined Benefit Pension Plan in 2020.

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. The Company's 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 (in thousands):

Pension Plan	**December 31, 2019**					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total
AXA Equitable General Fixed Income	$ —	$ 8	$ —	$ 8	$ —	$ 8
Common Collective Trust - Cash and Cash Equivalent	—	978	—	978	—	978
Common Collective Trust - Equity	—	12,072	—	12,072	—	12,072
Common Collective Trust - Fixed Income	—	42,449	—	42,449	—	42,449
Common Collective Trust - Real Estate	—	—	—	—	1,974	1,974
Hedge Funds	—	—	—	—	2,709	2,709
Total investments measured at fair value	$ —	$ 55,507	$ —	$ 55,507	$ 4,683	$ 60,190

Pension Plan	**December 31, 2018**					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Fair Value
AXA Equitable General Fixed Income	$ —	$ 261	$ —	$ 261	$ —	$ 261
Common Collective Trust - Cash and Cash Equivalent	—	1,388	—	1,388	—	1,388
Common Collective Trust - Equity	—	9,436	—	9,436	—	9,436
Common Collective Trust - Fixed Income	—	39,047	—	39,047	—	39,047
Common Collective Trust - Real Estate	—	9	—	9	1,896	1,905
Hedge Funds	—	—	—	—	2,627	2,627
Total investments measured at fair value	$ —	$ 50,141	$ —	$ 50,141	$ 4,523	$ 54,664

(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plan's benefit obligations and fair value of plan assets above.

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately placed 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 of 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 providers 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. The Plan's investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

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. The funds without participant withdrawal limitations are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

Common Collective Trust-Real Estate Fund: This is the same fund as above except that certain of the funds' assets contain participant withdrawal policies with restrictions on redemption and are therefore not included in the fair value hierarchy.

Hedge Funds: These 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. 20% of the shares may be redeemed at the end of each month with a 10-day notice and full redemptions are available at the end of each quarter with 45-day notice, and is limited to a percentage of the total net assets 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.

Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the Balance Sheets, components of the net periodic expense and elements of AOCI:

Benefit Obligations

	Defined Benefit Pension	Supplemental Non-qualified	Non-pension Defined

	Plan		Defined Benefit Plans		Benefit Postretirement Healthcare Plans	
As of December 31 (in thousands)	2019	2018	2019	2018	2019	2018
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 61,919	$ 67,562	$ 2,992	$ 3,418	$ 5,055	$ 5,970
Service cost	365	516	—	—	148	193
Interest cost	2,410	2,194	115	108	186	179
Actuarial (gain) loss	7,482	(2,878)	405	(296)	507	(889)
Benefits paid	(5,234)	(3,562)	(266)	(238)	(739)	(389)
Plan participants transfer to affiliate	119	(1,913)	—	—	(77)	(129)
Plan participants' contributions	—	—	—	—	96	120
Projected benefit obligation at end of year	$ 67,061	$ 61,919	$ 3,246	$ 2,992	$ 5,176	$ 5,055

Employee Benefit Plan Assets

As of December 31 (in thousands)	Defined Benefit Pension Plan 2019	Defined Benefit Pension Plan 2018	Supplemental Non-qualified Defined Benefit Plans 2019	Supplemental Non-qualified Defined Benefit Plans 2018	Non-pension Defined Benefit Postretirement Healthcare Plans 2019	Non-pension Defined Benefit Postretirement Healthcare Plans 2018
Beginning fair value of plan assets	$ 54,664	$ 59,884	$ —	$ —	$ —	$ —
Investment income (loss)	8,902	(1,884)	—	—	—	—
Benefits paid	1,753	1,795	266	238	643	268
Participant contributions	—	—	—	—	96	120
Employer contributions	(5,234)	(3,563)	(266)	(238)	(739)	(388)
Plan participants transfer to affiliate	105	(1,568)	—	—	—	
Ending fair value of plan assets	$ 60,190	$ 54,664	$ —	$ —	$ —	$ —

The funded status of the plans and amounts recognized in the Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan 2019	Defined Benefit Pension Plan 2018	Supplemental Non-qualified Defined Benefit Plans 2019	Supplemental Non-qualified Defined Benefit Plans 2018	Non-pension Defined Benefit Postretirement Healthcare Plans 2019	Non-pension Defined Benefit Postretirement Healthcare Plans 2018
Regulatory assets	$ 20,117	$ 19,099	$ —	$ —	$ —	$ —
Current liabilities	$ —	$ —	$ 321	$ 230	$ 586	$ 466
Non-current liabilities	$ 7,121	$ 7,255	$ 2,925	$ 2,762	$ 4,590	$ 4,589
Regulatory liabilities	$ —	$ —	$ —	$ —	$ 1,675	$ 2,441

Accumulated Benefit Obligation

As of December 31 (in thousands)	Defined Benefit Pension Plan 2019	Defined Benefit Pension Plan 2018	Supplemental Non-qualified Defined Benefit Plans 2019	Supplemental Non-qualified Defined Benefit Plans 2018	Non-pension Defined Benefit Postretirement Healthcare Plans 2019	Non-pension Defined Benefit Postretirement Healthcare Plans 2018
Accumulated benefit obligation	$ 65,225	$ 59,987	$ 3,246	$ 2,992	$ 5,176	$ 5,055

Components of Net Periodic Expense

Net periodic expense consisted of the following for the year ended December 31 (in thousands):

	Defined Benefit Pension Plan 2019	Defined Benefit Pension Plan 2018	Supplemental Non-qualified Defined Benefit Plans 2019	Supplemental Non-qualified Defined Benefit Plans 2018	Non-pension Defined Benefit Postretirement Healthcare Plans 2019	Non-pension Defined Benefit Postretirement Healthcare Plans 2018
Service Cost	$ 365	$ 516	$ —	$ —	$ 148	$ 193
Interest Cost	2,410	2,194	114	108	186	179
Expected return on assets	(3,405)	(3,545)	—	—	—	—
Amortization of prior service cost (credits)	10	43	—	—	(336)	(336)
Recognized net actuarial loss (gain)	1,221	2,063	65	103	—	—
Net periodic expense	$ 601	$ 1,271	$ 179	$ 211	$ (2)	$ 36

AOCI

For defined benefit plans, 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 Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2019	2018	2019	2018	2019	2018
Net (gain) loss	$ —	$ —	$ 812	$ 391	$ —	$ —
Total AOCI	$ —	$ —	$ 812	$ 391	$ —	$ —

Assumptions

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2019	2018	2019	2018	2019	2018
Weighted-average assumptions used to determine benefit obligations:						
Discount rate	3.27%	4.40 %	3.10%	4.30 %	3.15%	4.28%
Rate of increase in compensation levels	3.49%	3.52 %	N/A	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:						
Discount rate (a)	4.40%	3.71 %	4.30%	3.62 %	4.28%	3.60%
Expected long-term rate of return on assets (b)	6.00%	6.25 %	N/A	N/A	3.00%	3.93%
Rate of increase in compensation levels	3.52%	3.43 %	N/A	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 3.27% for the calculation of the 2020 net periodic pension costs.

(b) The expected rate of return on plan assets is 5.25% for the calculation of the 2020 net periodic pension cost.

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

	2019	2018
Trend Rate - Medical		
Pre-65 for next year	6.40%	6.70%
Pre-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2027	2027
Post-65 for next year	4.92%	4.94%
Post-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2028	2026

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

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plans
2020	$ 3,620	$ 321	$ 586
2021	$ 3,766	$ 317	$ 622
2022	$ 3,833	$ 315	$ 591
2023	$ 3,951	$ 311	$ 522
2024	$ 4,022	$ 308	$ 474
2025-2028	$ 19,882	$ 1,142	$ 1,853

(13) COMMITMENTS AND CONTINGENCIES

We have the following power purchase and transmission services agreements, not including related party agreements, as of December 31, 2019 (see Note 14 for information on related party agreements):

- A PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. 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 service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- A PPA with Platte River Power Authority (PRPA) to purchase up to 12 MW of wind energy through PRPA's agreement with Silver Sage Wind Farm, LLC. This agreement will expire September 30, 2029.

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

Contract	Contract Type	2019	2018
PacifiCorp	Electric capacity and energy	$ 7,477	$ 13,681
PacifiCorp	Transmission access	$ 1,741	$ 1,742
Thunder Creek [(a)]	Gas transport capacity	$ 422	$ 633

PRPA	Wind energy	$	688	$	223

(a) Agreement with Thunder Creek for gas transport capacity, expired in October 2019.

Future Contractual Obligations

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

2020	$	6,531
2021	$	6,203
2022	$	6,203
2023	$	6,203
2024	$	—
Thereafter	$	—

Power Sales Agreements

We have the following significant long-term power sales contracts with non-affiliated third-parties:

- 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. This agreement expires January 31, 2023.

- An agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023. Additionally, we have firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming to serve our power sales contract with MDU through December 31, 2023, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

- 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, which is renewed annually on September 3, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- We have an amended agreement, effective January 1, 2019, to supply up to 20 MW of energy and capacity to MEAN under a contract that expires May 31, 2028. The terms of the contract run from June 1 through May 31 for each interval listed below. This contract is unit-contingent based on the availability of our Wygen III and Neil Simpson II plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

Contract Years	Total Contract Capacity	Contingent Capacity Amounts on Wygen III	Contingent Capacity Amounts on Neil Simpson II
2019-2020	15 MW	10 MW	5 MW
2020-2022	15 MW	7 MW	8 MW
2022-2023	15 MW	8 MW	7 MW
2023-2028	10 MW	5 MW	5 MW

- An agreement through December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals.

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. 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.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the financial statements.

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.

(14) RELATED-PARTY TRANSACTIONS

Non-Cash Dividend to Parent

We did not record any dividends in 2019. We recorded non-cash dividends to our Parent of $36 million in 2018 and changed the Utility Money Pool note by $36 million in 2018.

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):

	2019	2018
Accounts Receivable from Assoc. Companies (146)	$ 13,038	$ 8,122
Accounts Payable to Associated Companies (234)	$ 32,121	$ 25,804

Money Pool Notes Receivable and Notes Payable

We participate in the Utility Money Pool Agreement (the Agreement). Under the Agreement, we may borrow from the pool; however the Agreement restricts the pool from loaning funds to BHC or to any of BHC's non-utility subsidiaries. The Agreement does not restrict us from paying dividends to BHC. Borrowings under the Agreement bear interest at the weighted average daily cost of BHC's external 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 plus 1.0%. The cost of borrowing under the Utility Money Pool was 2.21% at December 31, 2019

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

	2019	2018
Money pool notes payable -- Notes Payable to Associated Companies (233)	$ 57,585	$ 38,847
Money pool interest payable -- Notes Payable to Associated Companies (233)	$ 103	$ 97

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

	2019	2018
Interest on Debt to Assoc. Companies (430)	$ (775)	$ (401)

Notes payable to Parent

On June 1, 2019, we entered into a $25 million, 4.51% short-term promissory note with BHC. Interest accrued and a prorated portion of the financing costs were paid monthly through expiration of the note on December 31, 2019. The note is eligible for annual renewal, was renewed through December 31, 2020, and will bear interest at 4.11%. Interest payable related to this note was $0.2 million as of December 31, 2019.

	2019	2018
Notes payable to Parent -- Notes Payable to Associated Companies (233)	$ 25,000	$ —

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2019, and 2018, we were allocated $1.2 million and $1.3 million, respectively, of interest expense from BHC.

Other Balances and Transactions

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

- Wyoming Electric has a PPA with Happy Jack Wind Farm, LLC, expiring September 3, 2028, which provides up to 30 MW of wind energy. Under a separate intercompany agreement, Wyoming Electric sells 50% of the facility output to South Dakota Electric.

- Wyoming Electric has a PPA with Silver Sage Wind Farm, LLC, expiring September 30, 2029, which provides up to 30 MW of wind energy. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of energy from Silver Sage to South Dakota Electric.

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

- A Wygen III Ground Lease with Wyodak Resources Development Corporation (WRDC) mine expiring in 2050 with three automatic renewal terms of 20 years each.

Related-party Gas Transportation Service Agreement

On October 1, 2014, we entered into a gas transportation service agreement with Wyoming Electric in connection with gas supply for Cheyenne Prairie. The agreement is for a term of 40 years, in which we pay a monthly service and facility fee for firm and interruptible gas transportation.

Related-party Revenue and Purchases

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

	2019	2018
	(in thousands)	
Operating Revenues:		
Energy sold to Wyoming Electric	$ 1,333	$ 2,064
Rent from electric properties	$ 3,583	$ 3,634
Horizon Point shared facility revenue	$ 12,026	$ 11,211
Operating Expenses:		
Purchases from WRDC mine	$ 17,041	$ 17,532
Purchase of excess energy from Wyoming Electric	$ 856	$ 511
Purchase of renewable wind energy from Wyoming Electric - Happy Jack	$ 1,968	$ 1,942
Purchase of renewable wind energy from Wyoming Electric - Silver Sage	$ 3,579	$ 3,586
Gas transportation service agreement with Wyoming Electric for firm and interruptible gas transportation	$ 309	$ 364

Related-party Corporate Support

We had the following corporate support for the years ended December 31:

	2019	2018
	(in thousands)	
Corporate support services and fees from Parent, Black Hills Service Company and Black Hills Utility Holdings	$ 39,667	$ 34,578

Horizon Point Agreement

South Dakota Electric and BHSC are parties to a shared facilities agreement, whereby BHSC is charged for the use of the Horizon Point facility that is owned by South Dakota Electric and BHSC provides certain operations and maintenance services at the facility.

(15) SUBSEQUENT EVENT

Management has evaluated the impact of events occurring after December 31, 2019 up to February 18, 2020, the date our GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 24, 2020. These financial statements contain all necessary adjustments and disclosures resulting from that evaluation.

COVID-19 Pandemic

We are responding to the global outbreak (pandemic) of COVID-19 by taking steps to mitigate the potential risks to us posed by its spread. We provide an essential service to our customers which means that it is paramount that we keep our employees who operate our businesses safe and minimize unnecessary risk of exposure to the virus. We continue to execute our business continuity plan and have implemented a comprehensive set of actions for the health and safety of our customers, employees, business partners and the communities we serve. We have taken extra precautions for our employees who work in the field and for employees who continue to work in our facilities, and we have implemented work from home policies where appropriate. We have implemented sequestration plans for employees critical to maintaining reliable service. We have informed both our customers and regulators that disconnections for non-payment will be temporarily suspended.

We have instituted measures to ensure our supply chain remains open to us; however, there could be shortages that will impact our operations and maintenance and capital programs that we currently cannot anticipate. We continue to implement strong physical and cyber-security measures to ensure that our systems remain functional in order to both serve our operational needs with a remote workforce and keep them running to ensure uninterrupted service to our customers.

To date, we have not experienced significant impacts to our results of operations, financial condition, cash flows or business plans. However, the situation remains fluid and it is difficult to predict with certainty the potential impact of the virus on our business, operations, financial condition and cash flows.