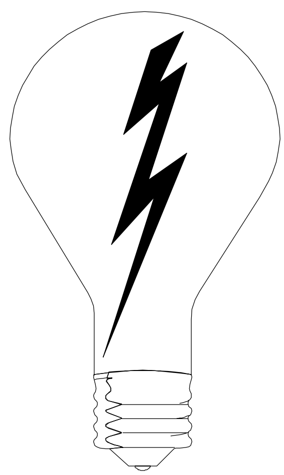
YEAR ENDING 2021

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

Table of Contents

continued on next page

IDENTIFICATION

Year: **2021**

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: 2021

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President & Chief Executive Officer		Linden R. Evans
2	Sr. Vice President and Chief Financial Officer		Richard W. Kinzley
3	Sr. Vice President and General Counsel		Brian G. Iverson
4	Sr. Vice President - Chief Human Resources Officer		Jennifer C. Landis
5	Sr. Vice President - Utility Operations		Stuart A. Wevik
6	Sr. Vice President - Chief Information Officer		Erik D. Keller
7	Vice President - BHE South Dakota		Marc Eyre
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Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 4

CORPORATE STRUCTURE

Year: 2021

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	51,794,163	100.00%
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42				100.00%
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50	**TOTAL**		51,794,163	

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

CORPORATE ALLOCATIONS

Year: 2021

	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: 2021

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Wyodak Resources Development Corp.	Coal Sales to Utility	Fair Market Value (based on similar arms-length transactions)	16,344,666	29.03%	1,176,816
2	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions)	6,928,681	3.67%	498,865
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	47,815,919	82.47%	3,442,746
4	Cheyenne Light Fuel and Power	Renewable Wind Energy Sales	Fixed PPA Pricing	4,912,049	2.60%	353,668
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32	**TOTAL**			76,001,314		5,472,095

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2021

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	Wyodak Resources Development Corp.	Electricity	Wyoming Industrial Rate	1,058,470	100.00%	
2	Black Hills Wyoming	Transmission Service	Point to Point open Access Transmission Tariff	129,586	100.00%	
3	Cheyenne Light Fuel and Power	Transmission Service	Point to Point Open Access Transmission Tariff Fair Market	10,055,783	9.18%	724,016
4	Black Hills Wyoming	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	48,342	100.00%	3,481
5	Cheyenne Light Fuel and Power	Non-Firm Energy Sales	Fair Market Value (based on similar arms-length transactions	4,546,566	4.15%	327,353
6	Cheyenne Light Fuel and Power	Neil Simpson Complex	Fair Market Value (based on similar arms-length transactions	8,332,459	7.61%	599,937
7	Cheyenne Light Fuel and Power	Environmental Complex	Fair Market Value (based on similar arms-length transactions	124,805	0.11%	8,986
8	Cheyenne Light Fuel and Power	GDPM	Fair Market Value (based on similar arms-length transactions	10,352	0.01%	745
9	Black Hills Service Company	Corporate Headquarter Shared Facility Agreement	Revenue Requirement	11,293,536	23.13%	813,135
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32	**TOTAL**			35,599,899		2,477,653

MONTANA UTILITY INCOME STATEMENT

Year: 2021

		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	303,367,621	353,935,773	16.67%
2					
3		Operating Expenses			
4	401	Operation Expenses	141,693,409	188,445,145	32.99%
5	402	Maintenance Expense	22,087,069	22,216,920	0.59%
6	403	Depreciation Expense	42,575,695	46,429,960	9.05%
7	404-405	Amortization of Electric Plant	1,774,436	1,774,436	
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	10,880,795	11,217,067	3.09%
12	409.1	Income Taxes - Federal	7,309,643	5,090,832	-30.35%
13		- Other			
14	410.1	Provision for Deferred Income Taxes	15,737,124	58,411,252	271.17%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(17,747,661)	(57,965,249)	-226.61%
16	411.4	Investment Tax Credit Adjustments			
17	411.6	(Less) Gains from Disposition of Utility Plant			
18	411.10	Accretion Expense	1,686	25,877	1434.82%
19					
20		**TOTAL Utility Operating Expenses**	224,409,602	275,743,646	22.88%
21		**NET UTILITY OPERATING INCOME**	78,958,019	78,192,127	-0.97%

MONTANA REVENUES

SCHEDULE 9

		Account Number & Title	Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	7,083	7,027	-0.79%
3	442	Commercial & Industrial - Small	18,689	18,434	-1.36%
4		Commercial & Industrial - Large	9,607,554	9,421,558	-1.94%
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**	9,633,326	9,447,019	-1.93%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	9,633,326	9,447,019	-1.93%
14	449.1	(Less) Provision for Rate Refunds	(1,238,986)		100.00%
15					
16		**TOTAL Revenue Net of Provision for Refunds**	10,872,312	9,447,019	-13.11%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	4	10	150.00%
19	451	Miscellaneous Service Revenues	23	45	95.65%
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**	27	55	103.70%
26		**Total Electric Operating Revenues**	10,872,339	9,447,074	-13.11%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2021

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,124,715	1,144,989	1.80%
6	501 Fuel	19,711,385	19,207,267	-2.56%
7	502 Steam Expenses	1,589,496	1,732,353	8.99%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	589,210	572,409	-2.85%
11	506 Miscellaneous Steam Power Expenses	1,406,798	1,468,520	4.39%
12	507 Rents	2,660,405	2,931,307	10.18%
13				
14	TOTAL Operation - Steam	27,082,009	27,056,845	-0.09%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	813,890	777,305	-4.50%
18	511 Maintenance of Structures	558,126	523,695	-6.17%
19	512 Maintenance of Boiler Plant	4,980,274	5,690,794	14.27%
20	513 Maintenance of Electric Plant	974,944	1,010,501	3.65%
21	514 Maintenance of Miscellaneous Steam Plant	54,929	48,713	-11.32%
22				
23	TOTAL Maintenance - Steam	7,382,163	8,051,008	9.06%
24				
25	**TOTAL Steam Power Production Expenses**	34,464,172	35,107,853	1.87%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2021

	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	951,066	932,620	-1.94%
27	547 Fuel	6,589,513	30,982,775	370.18%
28	548 Generation Expenses	90,369	735,119	713.46%
29	549 Miscellaneous Other Power Gen. Expenses	444,345	599,873	35.00%
30	550 Rents	295,426	444,887	50.59%
31				
32	TOTAL Operation - Other	8,370,719	33,695,274	302.54%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	2,899	11,043	280.92%
36	552 Maintenance of Structures	6,941	9,179	32.24%
37	553 Maintenance of Generating & Electric Plant	2,159,703	1,894,595	-12.28%
38	554 Maintenance of Misc. Other Power Gen. Plant	57,174	80,703	41.15%
39				
40	TOTAL Maintenance - Other	2,226,717	1,995,520	-10.38%
41				
42	**TOTAL Other Power Production Expenses**	10,597,436	35,690,794	236.79%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	37,552,692	56,874,760	51.45%
46	556 System Control & Load Dispatching	1,148,415	1,024,424	-10.80%
47	557 Other Expenses	255		-100.00%
48				
49	TOTAL Other Power Supply Expenses	38,701,362	57,899,184	49.61%
50				
51	**TOTAL Power Production Expenses**	83,762,970	128,697,831	53.65%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2021

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	1,029,086	995,709	-3.24%
4	561	Load Dispatching	2,179,310	2,141,512	-1.73%
5	562	Station Expenses	403,419	325,104	-19.41%
6	563	Overhead Line Expenses	65,866	117,142	77.85%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others	22,919,417	25,962,457	13.28%
9	566	Miscellaneous Transmission Expenses	513,363	528,765	3.00%
10	567	Rents	40,786	42,205	3.48%
11					
12		TOTAL Operation - Transmission	27,151,247	30,112,894	10.91%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	3,217	195	-93.94%
15	569	Maintenance of Structures	30,037	32,271	7.44%
16	570	Maintenance of Station Equipment	159,723	171,885	7.61%
17	571	Maintenance of Overhead Lines	588,760	388,469	-34.02%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant	79	2,590	3178.48%
20					
21		TOTAL Maintenance - Transmission	781,816	595,410	-23.84%
22					
23		**TOTAL Transmission Expenses**	27,933,063	30,708,304	9.94%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering	1,426,449	1,147,530	-19.55%
28	581	Load Dispatching	482,034	493,264	2.33%
29	582	Station Expenses	606,486	630,125	3.90%
30	583	Overhead Line Expenses	348,552	207,693	-40.41%
31	584	Underground Line Expenses	428,639	402,093	-6.19%
32	585	Street Lighting & Signal System Expenses	66,886	86,066	28.68%
33	586	Meter Expenses	504,834	555,862	10.11%
34	587	Customer Installations Expenses	360,702	402,568	11.61%
35	588	Miscellaneous Distribution Expenses	1,537,345	1,498,296	-2.54%
36	589	Rents	(27,431)	7,762	128.30%
37					
38		TOTAL Operation - Distribution	5,734,496	5,431,259	-5.29%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	34,097	18,310	-46.30%
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment	157,059	299,506	90.70%
43	593	Maintenance of Overhead Lines	8,429,688	8,466,477	0.44%
44	594	Maintenance of Underground Lines	501,268	260,017	-48.13%
45	595	Maintenance of Line Transformers	47,605	57,517	20.82%
46	596	Maintenance of Street Lighting, Signal Systems	85,290	37,648	-55.86%
47	597	Maintenance of Meters	176,417	144,106	-18.32%
48	598	Maintenance of Miscellaneous Dist. Plant	60,872	45,667	-24.98%
49					
50		TOTAL Maintenance - Distribution	9,492,296	9,329,248	-1.72%
51					
52		**TOTAL Distribution Expenses**	15,226,792	14,760,507	-3.06%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2021

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	61,736	65,364	5.88%
4	902 Meter Reading Expenses	132,261	133,404	0.86%
5	903 Customer Records & Collection Expenses	1,289,253	1,216,732	-5.63%
6	904 Uncollectible Accounts Expenses	691,929	329,952	-52.31%
7	905 Miscellaneous Customer Accounts Expenses	293,582	274,155	-6.62%
8				
9	TOTAL Customer Accounts Expenses	2,468,761	2,019,607	-18.19%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	29,638	32,374	9.23%
14	908 Customer Assistance Expenses	403,310	579,920	43.79%
15	909 Informational & Instructional Adv. Expenses	22,016	4,387	-80.07%
16	910 Miscellaneous Customer Service & Info. Exp.	19,067	3,227	-83.08%
17				
18	TOTAL Customer Service & Info Expenses	474,031	619,908	30.77%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses	48,491	22,919	-52.74%
24	913 Advertising Expenses	28,054	4,049	-85.57%
25	916 Miscellaneous Sales Expenses			
26				
27	TOTAL Sales Expenses	76,545	26,968	-64.77%
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	13,838,061	13,564,371	-1.98%
32	921 Office Supplies & Expenses	4,106,609	3,559,973	-13.31%
33	922 (Less) Administrative Expenses Transferred - Cr.	(2,850,848)	(2,921,089)	-2.46%
34	923 Outside Services Employed	4,566,265	3,797,213	-16.84%
35	924 Property Insurance	780,369	756,467	-3.06%
36	925 Injuries & Damages	1,510,707	1,689,910	11.86%
37	926 Employee Pensions & Benefits	6,759,753	6,883,828	1.84%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	988,759	902,300	-8.74%
40	929 (Less) Duplicate Charges - Cr.	(228,286)	(246,929)	-8.17%
41	930.1 General Advertising Expenses	491,055	566,916	15.45%
42	930.2 Miscellaneous General Expenses	1,063,972	1,257,538	18.19%
43	931 Rents	1,756,493	1,772,709	0.92%
44				
45	TOTAL Operation - Admin. & General	32,782,909	31,583,207	-3.66%
46	Maintenance			
47	935 Maintenance of General Plant	2,204,077	2,245,733	1.89%
48				
49	**TOTAL Administrative & General Expenses**	34,986,986	33,828,940	-3.31%
50				
51	**TOTAL Operation & Maintenance Expenses**	164,929,148	210,662,065	27.73%

MONTANA TAXES OTHER THAN INCOME

Year: 2021

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	10,318	4,998	-51.56%
5	Montana PSC	40,053	29,865	-25.44%
6	Franchise Taxes			
7	Property Taxes	538,034	594,622	10.52%
8	Tribal Taxes			
9		21,909	21,872	-0.17%
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51	**TOTAL MT Taxes Other Than Income**	610,314	651,357	6.72%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES Year: 2021

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

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2021

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

Pension Costs

Year: 2021

	Item	Current Year	Last Year	% Change
1	Plan Name			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit Method	IRS Code: 401b		
4	Annual Contribution by Employer: see line 20 below	Is the Plan Over Funded? No		
5				
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	69,395,497	67,060,844	-3.36%
8	Service cost	330,378	367,504	11.24%
9	Interest Cost	1,255,435	1,851,790	47.50%
10	Plan participants' contributions		-	
11	Amendments	(132,813)	-	100.00%
12	Actuarial Gain	(4,324,884)	5,982,892	238.34%
13	Acquisition	(378,843)	(53,962)	85.76%
14	Benefits paid	(4,929,930)	(5,813,571)	-17.92%
15	Benefit obligation at end of year	61,214,840	69,395,497	13.36%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	64,179,583	60,190,133	-6.22%
18	Actual return on plan assets	777,672	8,100,300	941.61%
19	Acquisition	(357,847)	(36,279)	89.86%
20	Employer contribution	-	1,739,000	#DIV/0!
21	Plan participants' contributions	-	-	
22	Benefits paid	(4,929,930)	(5,813,571)	-17.92%
23	Fair value of plan assets at end of year	59,669,478	64,179,583	7.56%
24	**Funded Status**	(1,545,362)	(5,215,914)	-237.52%
25	Unrecognized net actuarial loss	14,726,270	18,927,792	28.53%
26	Unrecognized prior service cost	(132,813)	-	100.00%
27	Prepaid (accrued) benefit cost	13,048,095	13,711,878	5.09%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	2.88%	2.56%	-11.11%
31	Expected return on plan assets	4.25%	4.50%	5.88%
32	Rate of compensation increase	3.08%	3.34%	8.44%
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	330,378	367,504	11.24%
36	Interest cost	1,255,435	1,851,790	47.50%
37	Expected return on plan assets	(2,824,111)	(3,124,940)	-10.65%
38	Amortization of prior service cost			
39	Recognized net actuarial loss	1,902,081	2,043,067	7.41%
40	Net periodic benefit cost	663,783	1,137,421	71.35%
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	335	372	11.04%
48	Not Covered by the Plan			
49	Active	118	127	7.63%
50	Retired	186	181	-2.69%
51	Deferred Vested Terminated	31	64	106.45%

Other Post Employment Benefits (OPEBS)

Year: 2021

	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	2.79%	2.41%	-13.62%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	5.10%	4.92%	-3.53%
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	5,100,183	5,176,300	1.49%
20	Service cost	167,376	157,120	-6.13%
21	Interest Cost	75,337	129,252	71.57%
22	Plan participants' contributions	109,799	106,711	-2.81%
23	Amendments	-	-	
24	Actuarial Gain	(286,717)	149,712	152.22%
25	Acquisition	23,252	431	-98.15%
26	Benefits paid	(741,032)	(619,343)	16.42%
27	Benefit obligation at end of year	4,448,198	5,100,183	14.66%
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	631,233	512,632	-18.79%
33	Plan participants' contributions	109,799	106,711	-2.81%
34	Benefits paid	(741,032)	(619,343)	16.42%
35	Fair value of plan assets at end of year		-	
36	**Funded Status**	(4,448,198)	(5,100,183)	-14.66%
37	Unrecognized net actuarial loss	(609,165)	(345,700)	43.25%
38	Unrecognized prior service cost	(507,523)	(843,265)	-66.15%
39	Prepaid (accrued) benefit cost	(5,564,886)	(6,289,148)	-13.01%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	167,376	157,120	-6.13%
42	Interest cost	75,337	129,252	71.57%
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	(93,026)	(49,367)	46.93%
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: 2021

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	320	317	-0.94%
3	Not Covered by the Plan			
4	Active	219	213	-2.74%
5	Retired	76	77	1.32%
6	Spouses/Dependants covered by the Plan	25	27	8.00%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost			
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ________________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	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	Jennifer C. Landis Sr. Vice President and Chief Human Resources 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.

PROXY

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, 2021, 2020 and 2019. We have no employment agreements with our Named Executive Officers:

Name and Principal Position	Year	Salary	Stock Awards(1)	Non-Equity Incentive Plan Compensation(2)	Changes in Pension Value and Nonqualified Deferred Compensation Earnings (3)	All Other Compensation(4)	Total
Linden R. Evans President and Chief Executive Officer	2021	$ 819,167	$ 2,238,529	$ 708,252	$ —	$ 674,960	$ 4,440,908
	2020	$ 783,333	$ 1,820,599	$ 936,632	$ 79,100	$ 601,450	$ 4,221,114
	2019	$ 713,333	$ 1,541,811	$ 800,400	$ 110,158	$ 473,600	$ 3,639,302
Richard W. Kinzley Sr. Vice President and Chief Financial Officer	2021	$ 454,000	$ 650,687	$ 274,770	$ —	$ 282,323	$ 1,661,780
	2020	$ 448,333	$ 538,547	$ 348,447	$ 51,945	$ 263,528	$ 1,650,800
	2019	$ 413,500	$ 524,220	$ 291,346	$ 68,631	$ 254,366	$ 1,552,063
Brian G. Iverson Sr. Vice President, General Counsel and Chief Compliance Officer	2021	$ 397,667	$ 510,213	$ 206,294	$ —	$ 170,934	$ 1,285,108
	2020	$ 384,167	$ 425,583	$ 275,609	$ 23,339	$ 157,216	$ 1,265,914
	2019	$ 370,833	$ 400,825	$ 240,120	$ 31,927	$ 156,990	$ 1,200,695
Stuart A. Wevik Sr. Vice President - Utility Operations (5)	2021	$ 422,000	$ 494,536	$ 255,403	$ 149,812	$ 114,904	$ 1,436,655
	2020	$ 398,601	$ 410,333	$ 333,625	$ 371,933	$ 121,870	$ 1,636,362
Erik D. Keller Sr. Vice President - Chief Information Officer (5)	2021	$ 338,333	$ 260,251	$ 146,261	$ —	$ 146,667	$ 891,512

(1) Stock Awards represent the grant date fair value related to restricted stock, performance shares and performance share units 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 14 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2021. The amounts shown for the performance shares and performance share units represent the values that are based on the achievement of 100% of the target performance. Assuming achievement of the maximum 200% of target performance, the value of the performance share units would be: $2,268,904 for Mr. Evans, $659,514 for Mr. Kinzley, $517,135 for Mr. Iverson, $501,244 for Mr. Wevik, and $263,782 for Mr. Keller.

(2) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2021 awards on January 25, 2022 and the awards were paid on March 4, 2022.

(3) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan and Pension Restoration Benefit ("PRB") for the respective years. These benefits have been valued using the assumptions disclosed in Note 13 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2021. 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 the change in discount rates used to calculate the present value of these benefits contributing significantly to the large increases in 2020 and 2019 and decreases in 2021.

The Pension Plan and PRB were frozen effective January 1, 2010 for participants who did not satisfy the age 45 and 10 years of service eligibility. Messrs. Evans, Kinzley and Iverson did not meet the eligibility choice criteria and their Defined Pension and PRB benefits were frozen.

Our Named Executive Officers receive employer contributions into a Nonqualified Deferred Compensation Plan ("NQDC"). The NQDC employer contributions are reported in the All Other Compensation column. No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The change in value attributed to each Named Executive Officer from each plan is shown in the table below:

	Year	Defined Benefit Plan	PRB	Total Change in Pension Value
Linden R. Evans	2021	$ (7,574)	$ (7,745)	$ (15,319)
	2020	$ 43,576	$ 35,524	$ 79,100
	2019	$ 59,664	$ 50,494	$ 110,158
Richard W. Kinzley	2021	$ (11,125)	$ (833)	$ (11,958)
	2020	$ 48,872	$ 3,073	$ 51,945
	2019	$ 64,428	$ 4,203	$ 68,631
Brian G. Iverson	2021	$ (4,089)	$ —	$ (4,089)
	2020	$ 23,339	$ —	$ 23,339
	2019	$ 31,927	$ —	$ 31,927
Stuart A. Wevik	2021	$ 149,812	$ —	$ 149,812
	2020	$ 371,933	$ —	$ 371,933
Erik D. Keller	2021	$ —	$ —	$ —

(4) All Other Compensation includes amounts allocated under the 401(k) match, defined contributions, Company contributions to defined benefit and deferred compensation plans, dividends received on restricted stock and unvested restricted stock units and other personal benefits. The Other Personal Benefits column reflects the personal use of a Company vehicle, executive health, moving expenses, and financial planning services for each NEO and relocation benefits in the amount of $52,532 for Mr. Keller.

	Year	401(k) Match	Defined Contributions	NQDC Contributions	Dividends on Restricted Stock	Other Personal Benefits	Total Other Compensation
Linden R. Evans	2021	$15,300	$ 23,200	$ 555,649	$ 65,057	$ 15,754	$ 674,960
Richard W. Kinzley	2021	$17,400	$ 21,100	$ 211,957	$ 19,394	$ 12,472	$ 282,323
Brian G. Iverson	2021	$17,400	$ 21,100	$ 107,397	$ 15,185	$ 9,852	$ 170,934
Stuart A. Wevik	2021	$ 8,250	$ —	$ 65,044	$ 15,277	$ 26,333	$ 114,904
Erik D. Keller	2021	$17,400	$ 11,600	$ 39,427	$ 12,835	$ 65,405	$ 146,667

(5) Mr. Wevik and Mr. Keller became NEOs in 2020 and 2021, respectively.

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

BALANCE SHEET

Year: 2021

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	1,322,200,264	1,414,369,567	-7%
4	101.1	Property Under Capital Leases	16,576,394	16,553,459	0%
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	198,635,636	158,177,984	26%
9	107	Construction Work in Progress - Electric	35,881,998	42,909,812	-16%
10	108	(Less) Accumulated Depreciation	(446,568,013)	(464,769,962)	4%
11	111	(Less) Accumulated Amortization			
12	114	Electric Plant Acquisition Adjustments	4,870,308	4,870,309	0%
13	115	(Less) Accum. Amort. Elec. Acq. Adj.	(3,911,178)	(4,008,584)	2%
14	118	Common Utility Plant In Service	26,026,522	28,423,892	
15	119	Common Util Plt-Acc Depr-Orig	(1,972,780)	(4,107,392)	
16	120	Nuclear Fuel (Net)			
17		**TOTAL Utility Plant**	1,153,005,603	1,193,685,537	-3%
18					
19	**Other Property & Investments**				
20	121	Nonutility Property			
21	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.			
22	123	Investments in Associated Companies			
23	123.1	Investments in Subsidiary Companies			
24	124	Other Investments	681,808	702,691	-3%
25	125	Sinking Funds			
26	128	Other Special Funds	4,657,249	2,904,795	
27		**TOTAL Other Property & Investments**	5,339,057	702,691	660%
28					
29	**Current & Accrued Assets**				
30	131	Cash			
31	132-134	Special Deposits			
32	135	Working Funds	4,996	4,966	1%
33	136	Temporary Cash Investments			
34	141	Notes Receivable			
35	142	Customer Accounts Receivable	14,636,630	17,277,398	-15%
36	143	Other Accounts Receivable	1,758,734	815,214	116%
37	144	(Less) Accum. Provision for Uncollectible Accts.	(255,787)	(173,368)	-48%
38	145	Notes Receivable - Associated Companies			
39	146	Accounts Receivable - Associated Companies	19,293,457	13,047,382	48%
40	151	Fuel Stock	1,041,059	806,103	29%
41	152	Fuel Stock Expenses Undistributed			
42	153	Residuals			
43	154	Plant Materials and Operating Supplies	27,059,500	26,383,932	3%
44	155	Merchandise			
45	156	Other Material & Supplies			
46	157	Nuclear Materials Held for Sale			
47	163	Stores Expense Undistributed	2,237,242	1,482,736	51%
48	165	Prepayments	3,140,099	4,525,712	-31%
49	171	Interest & Dividends Receivable			
50	172	Rents Receivable			
51	173	Accrued Utility Revenues	11,337,700	12,919,048	-12%
52	174	Miscellaneous Current & Accrued Assets	918,744	2,794,626	-67%
53	175	Derivative Instrument Assets	1,064,770	-	#DIV/0!
54		**TOTAL Current & Accrued Assets**	82,237,144	79,883,749	3%

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

BALANCE SHEET

Year: 2021

	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	2,383,184	2,250,294	6%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	182.3	Other Regulatory Assets	71,898,812	77,669,873	
10	183	Prelim. Survey & Investigation Charges	295,767	149,288	98%
11	184	Clearing Accounts	1,357,230	1,385,326	-2%
12	185	Temporary Facilities			
13	186	Miscellaneous Deferred Debits	4,720,808	5,362,139	-12%
14	187	Deferred Losses from Disposition of Util. Plant			
15	188	Research, Devel. & Demonstration Expend.			
16	189	Unamortized Loss on Reacquired Debt	719,004	498,699	44%
17	190	Accumulated Deferred Income Taxes	37,982,694	37,459,191	1%
18		**TOTAL Deferred Debits**	119,357,499	124,774,810	-4%
19					
20		**TOTAL Assets & Other Debits**	1,359,939,303	204,658,559	564%
		Account Title	Last Year	This Year	% Change
21					
22		**Liabilities and Other Credits**			
23					
24	**Proprietary Capital**				
25					
26	201	Common Stock Issued	23,416,396	23,416,396	
27	202	Common Stock Subscribed			
28	204	Preferred Stock Issued			
29	205	Preferred Stock Subscribed			
30	207	Premium on Capital Stock	42,076,811	42,076,811	
31	211	Miscellaneous Paid-In Capital			
32	213	(Less) Discount on Capital Stock			
33	214	(Less) Capital Stock Expense	(2,501,882)	(2,501,882)	
34	215	Appropriated Retained Earnings			
35	216	Unappropriated Retained Earnings	358,292,317	398,342,957	-10%
36	217	(Less) Reacquired Capital Stock			100%
37	219	(Less) Accumulated Other Comprehensive Income	(1,420,318)	(1,129,057)	
38		**TOTAL Proprietary Capital**	419,863,324	460,205,225	-9%
39					
40	**Long Term Debt**				
41					
42	221	Bonds	340,000,000	340,000,000	
43	222	(Less) Reacquired Bonds			
44	223	Advances from Associated Companies			
45	224	Other Long Term Debt			
46	225	Unamortized Premium on Long Term Debt			
47	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(77,970)	(73,830)	-6%
48		**TOTAL Long Term Debt**	339,922,030	339,926,170	0%

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

BALANCE SHEET

Year: 2021

	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	13,802,349	13,496,506	2%
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	414,905	405,521	2%
9	228.3	Accumulated Provision for Pensions & Benefits	12,615,935	7,956,930	59%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds	143,949	-	#DIV/0!
12		**TOTAL Other Noncurrent Liabilities**	26,977,138	21,858,957	23%
13					
14	**Current & Accrued Liabilities**				
15					
16	230	Asset Retirement Obligations	759,964	783,606	
17	231	Notes Payable			
18	232	Accounts Payable	20,576,090	24,875,740	-17%
19	233	Notes Payable to Associated Companies	170,996,488	172,792,358	-1%
20	234	Accounts Payable to Associated Companies	40,159,834	38,755,426	4%
21	235	Customer Deposits	2,161,550	1,832,730	18%
22	236	Taxes Accrued	7,551,189	9,468,439	-20%
23	237	Interest Accrued	4,654,225	4,666,261	0%
24	238	Dividends Declared			
25	239	Matured Long Term Debt			
26	240	Matured Interest			
27	241	Tax Collections Payable	1,058,414	1,150,998	-8%
28	242	Miscellaneous Current & Accrued Liabilities	5,707,046	5,787,328	-1%
29	243	Obligations Under Capital Leases - Current	316,852	317,923	0%
30	244		920,680	-	#DIV/0!
31		**TOTAL Current & Accrued Liabilities**	254,862,332	259,647,203	-2%
32					
33	**Deferred Credits**				
34					
35	252	Customer Advances for Construction	6,883,941	7,850,512	-12%
36	253	Other Deferred Credits	2,007,099	2,350,695	-15%
37	255	Accumulated Deferred Investment Tax Credits	102,204,236	99,793,162	2%
38	256	Deferred Gains from Disposition Of Util. Plant			
39	257	Unamortized Gain on Reacquired Debt			
40	281-283	Accumulated Deferred Income Taxes	117,059,558	157,741,885	-26%
41		**TOTAL Deferred Credits**	228,154,834	267,736,254	-15%
42					
43	**TOTAL LIABILITIES & OTHER CREDITS**		1,269,779,658	1,371,232,766	-7%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2021

	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**			

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

SCHEDULE 19

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2021

	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		52,392	-100%
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**			52,392	-100%
31					
32	**Distribution Plant**				
33					
34	360	Land & Land Rights	26,304	26,304	0%
35	361	Structures & Improvements	(4,805)	(4,805)	0%
36	362	Station Equipment	8,882	9,524	-7%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	512,061	523,587	-2%
39	365	Overhead Conductors & Devices	494,753	496,996	0%
40	366	Underground Conduit	(1,326)	(1,326)	0%
41	367	Underground Conductors & Devices	13,144	13,144	0%
42	368	Line Transformers	83,825	86,014	-3%
43	369	Services	8,109	8,109	0%
44	370	Meters	(2,926)	(493)	-493%
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49	**TOTAL Distribution Plant**		1,138,020	1,157,054	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2021

	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**		1,138,445	1,209,871	

MONTANA DEPRECIATION SUMMARY

Year: 2021

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production				
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production				
6	Transmission				
7	Distribution	1,209,446	1,041,604	1,041,836	
8	General	425	169	195	
9	**TOTAL**	1,209,871	1,041,773	1,042,031	

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		57.52%		
13	Preferred Stock				
14	Long Term Debt		42.48%		
15	Other				
16	**TOTAL**		100.00%		

STATEMENT OF CASH FLOWS

Year: 2021

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	53,936,910	51,794,163	4%
6	Depreciation	42,577,381	46,455,837	-8%
7	Amortization	1,871,842	1,871,842	
8	Deferred Income Taxes - Net	(2,010,537)	446,003	-551%
9	Investment Tax Credit Adjustments - Net			
10	Change in Operating Receivables - Net	(8,709,095)	2,948,238	-395%
11	Change in Materials, Supplies & Inventories - Net	(3,306,478)	1,665,030	-299%
12	Change in Operating Payables & Accrued Liabilities - Net	(3,419,090)	3,774,279	-191%
13	Allowance for Funds Used During Construction (AFUDC)	10,492	101	10288%
14	Change in Other Assets & Liabilities - Net	(1,242,181)	(12,661,050)	90%
15	Other Operating Activities (explained on attached page)	(306,582)	736,280	-142%
16	**Net Cash Provided by/(Used in) Operating Activities**	79,402,662	97,030,723	-18%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(133,666,524)	(84,758,428)	-58%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets			
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)			
27	**Net Cash Provided by/(Used in) Investing Activities**	(133,666,524)	(84,758,428)	-58%
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)	54,262,862	(12,272,295)	542%
46	**Net Cash Provided by (Used in) Financing Activities**	54,262,862	(12,272,295)	542%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(1,000)	-	#DIV/0!
49	**Cash and Cash Equivalents at Beginning of Year**	5,966	4,966	20%
50	**Cash and Cash Equivalents at End of Year**	4,966	4,966	

Attachment 23A

Footnotes for Statement of Cash Flow		**Year: 2021**
Bad debt expense		329,952
Deferred financing cost amortization		421,667
Employee benefit plan expense		785,023
Contributions to defined benefit pension plan		-
Mark-to-market gain on derivative asset		144,090
Change in regulatory assets and liabilities impacting income statement		3,370,488
Changes in other current and non-current assets		(4,321,412)
Changes in other current and non-current liabilities		6,472
Line 15, current year- Other Operating Activities consists of:		736,280
Gross Additions to Utility Plant (less nuclear fuel)		(93,684,007)
(Less) Allowance for Other Funds Used During Construction		(861,777)
Cost of removal net of salvage		8,055,785
Other investments		1,731,571
Line 19, current year - Construction/Acquisition of Property, Plant, and Equipment	$	(84,758,428)
Proceeds from Notes Payable to Parent		34,400,000
Dividend paid to Parent		(14,000,000)
Net Payments to Money Pool		(32,672,295)
Line 45, current year-Other Financing Activities consist of:		(12,272,295)

Footnotes for Statement of Cash Flow		**Year: 2020**
Bad debt expense	$	691,929
Deferred financing cost amortization	$	552,249
Employee benefit plan expense	$	1,297,615
Contributions to defined benefit pension plan	$	(1,739,000)
Mark-to-market gain on derivative asset	$	(144,090)
Non-cash charges to income offset in regulatory assets and liabilities	$	3,158,629
Other changes in current and non-current assets	$	(3,254,965)
Other changes in current and non-current liabilities	$	(868,949)
Line 15, current year- Other Operating Activities consists of:	$	(306,582)
Gross Additions to Utility Plant (less nuclear fuel)	$	(132,294,280)
(Less) Allowance for Other Funds Used During Construction	$	(1,301,343)
Plant removal costs net of salvage value	$	188,786
Other investments	$	(259,687)
Line 19, current year - Construction/Acquisition of Property, Plant, and Equipment	$	(133,666,524)
Proceeds from Notes Payable to Parent	$	55,000,000
Net borrowings from Money Pool	$	33,117,862
Long Term Debt	$	(2,855,000)
Dividend paid to Parent	$	(31,000,000)
Line 45, current year-Other Financing Activities consist of:	$	54,262,862

LONG TERM DEBT

Year: 2021

	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	84,283,201	85,000,000	4.43%	3,765,500	4.43%
2									
3	Series AE	08/02	08/32	75,000,000	74,008,936	75,000,000	7.23%	5,422,500	7.23%
4									
5	Series AF	10/09	11/39	180,000,000	177,598,327	180,000,000	6.125%	11,025,000	6.13%
6									
7	1994 A Environmental								
8	Improvement Bonds	06/94	06/24	2,855,000			1.64%	-	
9									
10	Series Y	6/15/1988	6/15/2018	6,000,000				-	
11	Series Z	5/29/1991	5/29/2021	35,000,000				-	
12	Series AB	9/1/1999	9/1/2024	45,000,000				311,543	
13	Series 2004 Campbell County	10/1/2004	10/1/2024	12,200,000				102,430	
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			441,055,000	335,890,465	340,000,000		20,626,973	6.07%

PREFERRED STOCK

Year: 2021

	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										
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19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2021

		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: 2021

	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: 2021

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,210
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	(1,042)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	168
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	9,447
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	9,447
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	9,447
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	12
36		Commercial	24
37		Industrial	7
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	43
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	102,520
45		Average Annual Residential Cost per (Kwh) (Cents) *	6.86
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	586
48		Gross Plant per Customer	

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

SCHEDULE 29

MONTANA CUSTOMER INFORMATION

Year: 2021

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties	2,903	12	24	7	43
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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20						
21						
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24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**	2,903	12	24	7	43

MONTANA EMPLOYEE COUNTS

Year: 2021

	Department	Year Beginning	Year End	Average
1	Not Applicable			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
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40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2022

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

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2021

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	26	15	291	266,090	22,427
2	Feb.	11	11	326	240,843	16,990
3	Mar.	1	19	290	276,895	36,208
4	Apr.	21	9	262	250,352	40,482
5	May	20	16	262	242,693	28,005
6	Jun.	15	17	359	311,943	59,519
7	Jul.	27	16	397	314,109	32,003
8	Aug.	17	17	365	308,128	43,090
9	Sep.	10	17	322	268,090	33,907
10	Oct.	5	16	283	293,763	53,746
11	Nov.	17	18	279	307,102	58,937
12	Dec.	29	18	299	319,094	47,470
13	**TOTAL**				3,399,102	472,784

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	1,493,228	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,829,453
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	352,041	for Resale	123,021
7	(Less) Energy for Pumping			
8	**NET Generation**	1,845,269	Non-Requirements Sales	
9	Purchases	1,526,190	for Resale	1,205,349
10	Power Exchanges			
11	Received	259,245	Energy Furnished	
12	Delivered	(231,602)	Without Charge	
13	**NET Exchanges**	27,643		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	7,676,047	Electric Utility	
16	Delivered	(7,676,047)		
17	**NET Transmission Wheeling**	-	Total Energy Losses	241,279
18	Transmission by Others Losses			
19	**TOTAL**	3,399,102	**TOTAL**	3,399,102

SOURCES OF ELECTRIC SUPPLY

Year: 2021

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	6,303
2					
3	Thermal	Ben French	Rapid City, SD	10	(425)
4					
5	Thermal	Wyodak	Gillette, WY	69	446,776
6					
7	Thermal	Neil Simpson II	Gillette, WY	84	615
8					
9	Thermal	Lange	Rapid City, SD	39	42,836
10					
11	Thermal	Neil Simpson CT	Gillette, WY	39	86,890
12					
13	Thermal	Wygen III	Gillette, WY	57	427
14					
15	Combined Cycle	Cheyenne Prairie	Cheyenne, WY	60	352,125
16					
17	Wind Farm	Corriedale Wind Energy	Cheyenne, WY	32	8,127
18					
19	Purchase	See Schedule 32			
20					
21	Wheeling	See Schedule 32			
22					
23	Total Interchange	See Schedule 32			
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**			488	943674

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

SCHEDULE 35

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2021

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	Not Applicable						
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	Not Applicable					
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	Not Applicable					
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					

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 36**

MONTANA CONSUMPTION AND REVENUES

Year: 2021

	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	$7,027	$7,083	103	104	12	12
2	Commercial - Small	$18,434	$18,689	155	153	24	24
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large	$9,421,558	$9,607,555	145,619	146,146	7	7
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**	$9,447,019	$9,633,327	145,877	146,403	43	43

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION

NOTES TO FINANCIAL STATEMENTS
December 31, 2021 and 2020

(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.
- 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 separately.

Use of Estimates

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.

COVID-19 Pandemic

In March 2020, the World Health Organization categorized COVID-19 as a pandemic and the President of the United States declared the outbreak a national emergency. The U.S. government has deemed electric and natural gas utilities to be critical infrastructure sectors that provide essential services during this emergency. As a provider of essential services, the Company has an obligation to provide services to our customers. The Company remains focused on protecting the health of our customers, employees and the communities in which we operate while assuring the continuity of our business operations.

The Company's Financial Statements reflect estimates and assumptions made by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Financial Statements and reported amounts of revenue and expenses during the reporting periods presented. The Company considered the impacts of COVID-19 on the assumptions and estimates used and determined that, for the year ended December 31, 2021, there were no material adverse impacts on the Company's results of operations.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. As of December 31, 2021 and 2020, we have no cash equivalents.

Revenue Recognition

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:

- <u>Regulated electric utility services tariffs</u> - Our regulated operations 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.

- <u>Power sales agreements</u> - 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 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 in Note 2 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 below.

Accounts Receivable and Allowance for Credit Losses

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 amounts net of allowance for credit losses.

We maintain an allowance for credit losses which reflects our best estimate of uncollectible trade receivables. We regularly review our trade receivable allowance 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 credit losses 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, expected losses, 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 credit losses for the years ended December 31, were as follows (in thousands):

Description	Balance at beginning of year	Additions charged to costs and expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at end of year
	(in thousands)				
Allowance for credit losses (Account 144):					
2021	$ 256	$ 330	$ 316	$ (729)	$ 173
2020	$ 160	$ 693	$ 1,652	$ (2,249)	$ 256

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). See additional information in Note 5.

Regulatory Accounting

Our regulated operations are subject to cost-of-service regulation and earnings oversight from federal and state regulatory 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, 2021 and 2020, we had total regulatory assets of $78 million and $72 million respectively, and total regulatory liabilities of $100 million and $102 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. We also capitalize interest, when applicable, on undeveloped leasehold costs. 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 Utility plant on the accompanying Balance Sheets.

Third parties reimburse the us for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to 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. The amounts capitalized are included in Property, plant and equipment on the accompanying Balance Sheets.

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, 2021 and 2020.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.3% in 2021 and 2.2% in 2020.

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.

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. In August 2002, we entered into a treasury lock, which are interest rate swaps, 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 designated 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 First Mortgage Bonds. See Note 10 for more information.

As of December 31, 2021, we had no outstanding derivatives on the Balance Sheet.

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 fair value information is included in Notes 6 and 11.

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 Issued Accounting Standards

Facilitation of the Effects of Reference Rate Reform on Financial Reporting, ASU 2020-04

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*, which provides relief for companies preparing for discontinuation of interest rates such as LIBOR. The amendments in this update provide optional expedients and exceptions for applying GAAP to contracts, hedging relationships and other transactions affected by reference rate reform if certain criteria are met. The amendments in this update apply only to contracts and hedging relationships that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform. The amendments in this update are elective and are effective upon the ASU issuance through December 31, 2022. We are currently evaluating if we will apply the optional guidance as we assess the impact of the discontinuance of LIBOR on our current arrangements and the potential impact on our financial position, results of operations and cash flows.

(2) REVENUE

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,	
	2021	2020
	(in thousands)	
Customer types:		
Retail	$ 236,218	203,452
Wholesale	34,887	31,814
Market - off-system sales	31,685	15,655
Transmission/Other	51,472	53,103
Revenue from contracts with customers	354,262	304,024
Other revenues	237	204
Total revenues	$ 354,499	304,228
Timing of revenue recognition:		
Services transferred over time	$ 354,262	304,024
Revenue from contracts with customers	$ 354,262	304,024

(3) PROPERTY PLANT AND EQUIPMENT

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

	FERC Accounts	2021	2021 Weighted Average Useful Life (in years)	2020	2020 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Electric plant:							
Production		$ 687,132	45	$ 664,374	43	25	61
Transmission		255,127	50	241,401	50	42	60
Distribution		487,693	45	473,031	45	21	62
Plant acquisition adjustment [(a)]		4,870	32	4,870	32	32	32
General		172,287	28	169,324	28	3	40
Operating lease assets		16,553		16,576			
Total plant-in-service	101-106,114	1,623,662		1,569,576			
Construction work in progress	107	42,910		35,882			
Total electric plant		1,666,572		1,605,458			
Less accumulated depreciation and amortization	108,110,111,115	(472,886)		(452,452)			
Electric plant net of accumulated depreciation and amortization		$1,193,686		$1,153,006			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 10 years remaining.

(4) JOINTLY OWNED FACILITIES

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

Wyodak Plant

We own a 20% interest in the Wyodak Plant, a 402.3 MW mine-mouth coal-fired electric generating station located at the Gillette, Wyoming energy complex. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. We receive our proportionate share of the Wyodak Plant's capacity and are committed to pay our proportionate share of its additions, replacements and operating and maintenance expenses.

Transmission Tie

We jointly operate an electric transmission system, referred to as the Common Use System, with Basin Electric Power Cooperative and Powder River Energy Corporation. Each participant in the Common Use System individually owns assets that are operated together for a single system. The Common Use System also provides transmission service to our transmission tie.

We own a 35% share of a Direct Current transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western and eastern United States, respectively. Basin Electric Power Cooperative owns the remaining ownership percentage. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West. We are committed to pay our proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

Wygen III

We own a 52% interest in the Wygen III generation facility, a 116 MW mine-mouth, coal-fired power plant located at the Gillette, Wyoming energy complex. 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 their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations.

Cheyenne Prairie

Cheyenne Prairie, a 140 MW natural-gas fired power generation facility, was placed into commercial operations on October 1, 2014. The facility includes one combined-cycle 100 MW unit that we jointly own with Wyoming Electric, our related party operating in the Cheyenne, Wyoming area. We own 58 MW, and Wyoming Electric owns 42 MW of this combined-cycle unit. Cheyenne Prairie also includes one simple-cycle 40 MW combustion turbine that Wyoming Electric wholly owns. Black Hills Service Company (BHSC) is responsible for plant operations. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

Corriedale

Corriedale, a 52.5 MW wind farm near Cheyenne, Wyoming, was placed into commercial operation on November 30, 2020. This wind farm serves as the dedicated wind energy supply for Renewable Ready customers in South Dakota and Wyoming. We own 32.5 MW and Wyoming Electric owns 20 MW of this wind farm. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses. BHSC is responsible for operations of the wind farm.

As of December 31, 2021, 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	Less Accumulated Depreciation	Plant Net of Accumulated Depreciation
Wyodak Plant	$ 118,637	$ 882	$ (70,468)	$ 49,051
Transmission Tie	$ 24,544	$ 287	$ (6,922)	$ 17,909
Wygen III	$ 142,199	$ 635	$ (26,598)	$ 116,236
Cheyenne Prairie	$ 105,610	$ 50	$ (19,149)	$ 86,511
Corriedale	$ 48,888	$ —	$ (2,311)	$ 46,577

(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, 2021	December 31, 2021	December 31, 2020
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			(74)	(78)
Total Long-term Debt			$ 339,926	$ 339,922

Amortization of Deferred Financing Costs

Net deferred financing costs of approximately $2.3 million and $2.4 million were recorded on the accompanying Balance Sheets in Deferred Debits - Unamortized Debt Expenses (181) at December 31, 2021 and 2020, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.2 million for the years ended December 31, 2021 and 2020 are included in Interest Charges - Amort. of Debt Disc. And Expense (428) on the accompanying Statements of Income.

Debt Covenants

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, 2021.

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):

2022	$	—
2023	$	—
2024	$	—
2025	$	—
2026	$	—
Thereafter	$	340,000

(6) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

Pension and Postretirement Plan Assets

A discussion of the fair value of our Pension and Postretirement Plan assets is included in Note 11.

Other fair value measures

The carrying amount of cash, Money pool notes payable and Notes payable to Parent approximate fair value due to their liquid or short-term nature. Cash is classified in Level 1 in the fair value hierarchy. Money pool notes payable and Notes payable to Parent are not traded on an exchange and are classified in Level 2 in the fair value hierarchy.

The following table presents the carrying amounts and fair values of financial instruments not recorded at fair value on the Balance Sheets at December 31 (in thousands):

	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt [(a)]	$ 339,926	$ 469,777	$ 339,922	$ 504,374

(a) 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.

(7) REGULATORY MATTERS

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

	2021	2020
Regulatory assets		
Winter Storm Uri [(a)]	8,826	—
Deferred energy and fuel cost adjustments [(b)]	28,352	24,519
Deferred taxes on AFUDC [(c)]	4,438	4,650
Employee benefit plans [(d)]	14,890	19,244
Deferred taxes on flow through accounting [(b)]	14,117	11,943
Decommissioning costs [(c)]	2,662	4,436
Vegetation management [(b)]	3,455	5,759
Other regulatory assets [(b)]	930	1,348
Total Other Regulatory Assets (182.3)	77,670	71,899
Regulatory liabilities		
Employee benefit plans and related deferred taxes [(d)]	4,996	6,220
Excess deferred income taxes [(d)]	93,488	95,109
Other regulatory liabilities [(d)]	1,309	875
Total Other Regulatory Liabilities (254)	99,793	102,204

(a) In May 2021, we received approval from the South Dakota Public Utilities Commission (SDPUC) to recover costs from customers. See additional discussion below.
(b) Recovery of costs but we are not allowed a rate of return.
(c) In addition to recovery of costs, we are allowed a rate of return.
(d) 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.

Winter Storm Uri - See discussion below for Winter Storm Uri regulatory asset information.

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 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.

<u>Deferred Taxes on Flow-Through Accounting</u> - 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.

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

<u>Vegetation Management Costs</u> - 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.

<u>Employee Benefit Plans</u> **-** 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.

<u>Excess Deferred Income Taxes</u> - 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.

<u>Regulatory Activity</u>

<u>Winter Storm Uri</u>

In February 2021, a prolonged period of historic cold temperatures across the central United States, which covered all of our service territories, caused a substantial increase in heating and energy demand and contributed to unforeseeable and unprecedented market prices for natural gas and electricity. As a result of Winter Storm Uri, we incurred significant incremental fuel, purchased power and natural gas costs.

In May 2021, we received approval (Docket EL21-016) from the SDPUC to recover approximately $20 million of incremental and carrying costs from Winter Storm Uri from our South Dakota customers over a one-year period effective June 1, 2021. Additionally, we are recovering approximately $2.2 million of Winter Storm Uri incremental costs from our Wyoming customers through our existing regulatory mechanism. For the year ended December 31, 2021, we have collected $11 million of Winter Storm Uri incremental costs and carrying costs from customers.

<u>FERC Formula Rate</u>

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, 2021, the annual revenue requirement was $26 million and included estimated weighted average capital additions of $5 million for 2020 and 2021 combined.

(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 one year to 28 years, including options to extend that are reasonably certain to be exercised.

Most of our leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using our applicable incremental borrowing rate (weighted-average of 4.4% as of December 31, 2021).

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

	Income Statement Location	2021	2020
Operating lease cost	Operating Expenses (401)	$ 934	$ 929
Variable lease cost	Operating Expenses (401)	153	173
Total lease cost		$ 1,087	$ 1,102

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

	Balance Sheet Location	As of December 31, 2021	As of December 31, 2020
Assets:			
Operating leases	Utility Plant (101-106, 114)	$ 16,553	$ 16,576
Operating leases	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	(2,761)	(2,472)
Total lease assets		$ 13,792	$ 14,104
Liabilities:			
Operating leases	Obligations Under Capital Leases - Noncurrent (227)	$ 13,496	$ 13,802
Operating leases	Obligations Under Capital Leases - Current (243)	318	317
Total lease liabilities		$ 13,814	$ 14,119

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

	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 924	$ 922
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ —	$ 23

	As of December 31, 2021	As of December 31, 2020
Weighted average remaining lease term (years):		
Operating leases	28 years	29 years
Weighted average discount rate:		
Operating leases	4.4 %	4.4 %

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

	Total
2022	$ 912
2023	909
2024	907
2025	852
2026	852
Thereafter	19,442
Total lease payments	$ 23,874
Less imputed interest	10,060
Present value of lease liabilities	$ 13,814

(9) INCOME TAXES

Income Tax Expense

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

	2021	2020
Current income tax expense (Accounts 409.1 and 409.2)	$ 5,094	$ 7,352
Deferred income tax (benefit) (Accounts 410.1 and 411.1)	446	(2,010)
Total income tax expense (benefit)	$ 5,540	$ 5,342

Effective Tax Rates

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

	2021	2020
Federal statutory rate	21.0 %	21.0 %
Amortization of excess deferred income tax expense [(a)]	(3.0)%	(6.3)%
Flow-through adjustments [(b)]	(2.3)%	(2.4)%
Tax credits [(c)] [(d)]	(6.8)%	(4.4)%
Uncertain tax benefits	0.2 %	1.3 %
Other	0.5 %	(0.1)%
Effective tax rate	9.7 %	9.0 %

(a) Primarily TCJA — see Tax Reform section below for further details.
(b) 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.
(c) In November 2020, the Corriedale qualifying wind facility was placed in service and was eligible for production tax credits.
(d) In 2020, we completed a research and development study which encompassed tax years from 2013 to 2019.

Deferred Tax Assets and Liabilities

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

	2021	2020
Deferred tax assets:		
Regulatory liabilities	$ 23,243	$ 24,920
Accumulated depreciation and other plant-related differences	1,923	2,219
Employee benefit plans	1,821	1,721
Credit Carryovers	7,093	3,436
Other	3,379	5,687
Total deferred tax assets (Account 190)	$ 37,459	$ 37,983
Deferred tax liabilities:		
Regulatory assets	(9,075)	(7,313)
Accelerated depreciation and other plant related differences	$ (135,164)	$ (129,644)
Employee benefit plans	(3,248)	(3,196)
Deferred energy costs	(6,973)	(7,923)
Other	(3,282)	(4,950)
Total deferred tax liabilities (Accounts 282 and 283)	$ (157,742)	$ (153,026)
Net deferred tax assets (liabilities)	$ (120,283)	$ (115,043)

Winter Storm Uri costs, which will be deductible in our 2021 tax return, created a net deferred tax liability of approximately $4.4 million. The deferred tax liability will reverse with the same timing as the costs are recovered from our customers.

Unrecognized Tax Benefits

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):

	2021	2020
Unrecognized tax benefits at January 1	$ 916	$ 216
Additions for prior year tax positions	156	181
Additions for current year tax positions	(42)	616
Reductions for temporary unrecognized tax benefits	(158)	—
Reductions for prior year tax positions	—	(97)
Unrecognized tax benefits at December 31	$ 872	$ 916

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, 2021 and 2020, 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, 2022.

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	2021	2020
Protected		
FERC	$ 13.5	$ 13.3
State	68.5	67.9
Total protected	$ 82.0	$ 81.2
Unprotected		
FERC	$ 1.9	$ 2.3
State	9.6	11.6
Total unprotected	$ 11.5	$ 13.9
Total excess deferred income tax liabilities (account 254)	$ 93.5	$ 95.1

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 adjustments to the regulatory liability (account 254) for the year ended December 31, 2021, the estimated amortization period based on regulatory orders, and the accounts where the adjustments and amortization were reported are reflected below (in millions):

		Accounts								
Jurisdiction	December 31, 2020	190	236	254 Other	282	283	411 Amort.	409-411	December 31, 2021	Amortization Period
Protected										
FERC	$ 13.3	$ 0.1	$ —	$ 0.4	$ —	$ —	$ (0.3)	$ —	$ 13.5	(a)
State	67.9	0.1	—	2.0	—	—	(1.5)	—	68.5	(a)
Total protected	$ 81.2	$ 0.2	$ —	$ 2.4	$ —	$ —	$ (1.8)	$ —	$ 82.0	
Unprotected										
FERC	2.3	$ (0.1)	$ —	$ (0.4)	$ —	$ —	$ 0.1	$ —	$ 1.9	(b)
State	11.6	(0.4)	—	(2.0)	—	—	0.4	—	9.6	(b)
Total unprotected	$ 13.9	$ (0.5)	$ —	$ (2.4)	$ —	$ —	$ 0.5	$ —	$ 11.5	
Total excess deferred income tax liabilities (account 254)	$ 95.1	$ (0.3)	$ —	$ —	$ —	$ —	$ (1.3)	$ —	$ 93.5	

(a) The weighted average amortization period was estimated at 55-75 years under ARAM.
(b) The weighted average amortization period was estimated at 55-75 years under ARAM for plant-related unprotected and 1 year for non-plant unprotected.

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

(10) OTHER 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 following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Statements of Income for the period, net of tax (in thousands):

	Location on the Statement of Income	Amounts Reclassified from AOCI	
		2021	2020
Gains and Losses on cash flow hedges:			
Interest rate swaps gain (loss)	Misc Non Operating Income (421)	(65)	(64)
Income tax	Income Taxes Federal (409)	14	13
Total reclassification adjustments related to cash flow hedges, net of tax		(51)	(51)
Amortization of defined benefit plans:			
Actuarial gain (loss)	Misc Non Operating Income (421)	(162)	(125)
Income tax	Income Taxes Federal (409)	34	26
Total reclassification adjustments related to defined benefit plans, net of tax		(128)	(99)

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, 2020	$ (517)	$ (903)	$ (1,420)
Other comprehensive income (loss) before reclassifications	—	112	112
Amounts reclassified from AOCI	51	128	179
As of December 31, 2021	$ (466)	$ (663)	$ (1,129)
	Interest Rate Swaps	Employee Benefit Plans	Total
As of December 31, 2019	$ (568)	$ (812)	$ (1,380)
Other comprehensive income (loss) before reclassifications	—	(190)	(190)
Amounts reclassified from AOCI	51	99	150
As of December 31, 2020	$ (517)	$ (903)	$ (1,420)

(11) 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 is closed to new employees and frozen for certain employees who did not meet age and service based criteria.

The Pension Plan assets are held in a Master Trust. BHC's 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, 2021, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 22% to 30% return-seeking assets and 70% to 78% liability-hedging assets.

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

<u>Pension Plan Assets</u>

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

	2021	2020
Equity securities	15 %	21 %
Real estate	7 %	3 %
Fixed income funds	74 %	69 %
Cash and cash equivalents	1 %	3 %
Hedge funds	3 %	4 %
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 funded on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plan

BHC sponsors a retiree healthcare plan (Healthcare Plan) 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. The Healthcare Plan has no assets. We fund 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):

	2021	2020
Defined Contribution Plans		
Company Retirement Contribution	$ 1,006	$ 960
Matching Contributions	$ 1,345	$ 1,328
Defined Benefit Plans		
Defined Benefit Pension Plan	$ —	$ 1,739
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 629	$ 620
Supplemental Non-qualified Defined Benefit Plan	$ 321	$ 321

While we do not have required 2022 contributions, we currently expect to contribute $0.5 million to our Pension Plan.

Fair Value Measurements

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, 2021					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 782	$ —	$ 782	$ —	$ 782
Common Collective Trust - Equity	—	9,146	—	9,146	—	9,146
Common Collective Trust - Fixed Income	—	44,157	—	44,157	—	44,157
Common Collective Trust - Real Estate	—	—	—	—	3,958	3,958
Hedge Funds	—	—	—	—	1,626	1,626
Total investments measured at fair value	$ —	$ 54,085	$ —	$ 54,085	$ 5,584	$ 59,669

Pension Plan	December 31, 2020					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Fair Value
Common Collective Trust - Cash and Cash Equivalent	—	2,278	—	2,278	—	2,278
Common Collective Trust - Equity	—	13,590	—	13,590	—	13,590
Common Collective Trust - Fixed Income	—	44,010	—	44,010	—	44,010
Common Collective Trust - Real Estate	—	—	—	—	1,937	1,937
Hedge Funds	—	—	—	—	2,365	2,365
Total investments measured at fair value	$ —	$ 59,878	$ —	$ 59,878	$ 4,302	$ 64,180

(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.

Additional information about assets of the Pension Plan, including methods and assumptions used to estimate the fair value of these assets, is as follows:

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. Some of 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. 10% of the shares may be redeemed at the end of each month with a 15-day notice and full redemptions are available at the end of each quarter with 60-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, amounts recognized in the Balance Sheets, accumulated benefit obligation, reconciliation of components of the net periodic expense and elements of AOCI (in thousands):

<u>Benefit Obligations</u>

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2021	2020	2021	2020	2021	2020
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 69,396	$ 67,061	$ 3,249	$ 3,246	$ 5,100	$ 5,176
Service cost	330	368	—	—	167	157
Interest cost	1,256	1,852	51	84	75	129
Plan Amendments	(133)	—	—	—	—	—
Actuarial (gain) loss	(4,325)	5,983	(142)	240	(286)	150
Benefits paid	(4,930)	(5,814)	(321)	(321)	(741)	(619)
Plan participants transfer to affiliate	(379)	(54)	—	—	23	—
Plan participants' contributions	—	—	—	—	110	107
Projected benefit obligation at end of year	$ 61,215	$ 69,396	$ 2,837	$ 3,249	$ 4,448	$ 5,100

Fair Value of Employee Benefit Plan Assets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2021	2020	2021	2020	2021	2020
Beginning fair value of plan assets	$ 64,180	$ 60,190	$ —	$ —	$ —	$ —
Investment income (loss)	778	8,100	—	—	—	—
Benefits paid	—	1,739	(321)	(321)	631	513
Participant contributions	—	—	—	—	110	107
Employer contributions	(4,931)	(5,814)	321	321	(741)	(620)
Plan participants transfer to affiliate	(358)	(35)	—	—	—	
Ending fair value of plan assets	$ 59,669	$ 64,180	$ —	$ —	$ —	$ —

Amounts Recognized in the Balance Sheets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2021	2020	2021	2020	2021	2020
Other Regulatory Assets (182.3)	$ 14,593	$ 18,928	$ —	$ —	$ —	$ —
Miscellaneous Current and Accrued Liabilities (242)	$ —	$ —	$ 320	$ 320	$ 554	$ 629
Accumulated Provision for Pensions and Benefits (228.3)	$ 1,545	$ 5,216	$ 2,518	$ 2,929	$ 3,894	$ 4,471
Other Regulatory Liabilities (254)	$ —	$ —	$ —	$ —	$ 1,117	$ 1,189

Accumulated Benefit Obligation

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2021	2020	2021	2020	2021	2020
Accumulated benefit obligation	$ 60,726	$ 67,579	$ 2,837	$ 3,249	$ 4,448	$ 5,100

Components of Net Periodic Expense

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
For the years ended December 31,	2021	2020	2021	2020	2021	2020
Service Cost	$ 330	$ 367	$ —	$ —	$ 167	$ 157
Interest Cost	1,256	1,852	52	84	75	129
Expected return on assets	(2,824)	(3,125)	—	—	—	—
Amortization of prior service cost (credits)	—	—	—	—	(335)	(335)
Recognized net actuarial loss (gain)	1,902	2,043	162	125	—	—
Net periodic expense	$ 664	$ 1,137	$ 214	$ 209	$ (93)	$ (49)

AOCI Amounts (After-Tax)

As of December 31,	Defined Benefit Pension Plan 2021	Defined Benefit Pension Plan 2020	Supplemental Non-qualified Defined Benefit Plans 2021	Supplemental Non-qualified Defined Benefit Plans 2020	Non-pension Defined Benefit Postretirement Healthcare Plans 2021	Non-pension Defined Benefit Postretirement Healthcare Plans 2020
Net (gain) loss	$ —	$ —	$ 663	$ 903	$ —	$ —
Total amounts included in AOCI, after-tax not yet recognized as components of net periodic expense	$ —	$ —	$ 663	$ 903	$ —	$ —

Assumptions

	Defined Benefit Pension Plan 2021	Defined Benefit Pension Plan 2020	Supplemental Non-qualified Defined Benefit Plans 2021	Supplemental Non-qualified Defined Benefit Plans 2020	Non-pension Defined Benefit Postretirement Healthcare Plans 2021	Non-pension Defined Benefit Postretirement Healthcare Plans 2020
Weighted-average assumptions used to determine benefit obligations:						
Discount rate	2.88 %	2.56 %	2.70 %	2.32 %	2.79 %	2.41 %
Rate of increase in compensation levels	3.08 %	3.34 %	N/A	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:						
Discount rate [(a)]	2.56 %	3.27 %	2.32 %	3.10 %	2.41 %	3.15 %
Expected long-term rate of return on assets [(b)]	4.50 %	5.25 %	N/A	N/A	1.80 %	2.35 %
Rate of increase in compensation levels	3.34 %	3.49 %	N/A	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 2.88% for the calculation of the 2022 net periodic pension costs.
(b) The expected rate of return on plan assets is 4.25% for the calculation of the 2022 net periodic pension cost.

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

	2021	2020
Trend Rate - Medical		
Pre-65 for next year - All Plans	6.05 %	6.10 %
Pre-65 Ultimate trend rate	4.50 %	4.50 %
Trend Year	2030	2027
Post-65 for next year - All Plans	5.10 %	4.92 %
Post-65 Ultimate trend rate	4.50 %	4.50 %
Trend Year	2030	2029

Estimated Future Benefit Payments

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
2022	$ 3,837	$ 320	$ 554
2023	$ 3,935	$ 315	$ 490
2024	$ 3,964	$ 310	$ 439
2025	$ 3,938	$ 280	$ 418
2026	$ 3,908	$ 241	$ 401
2027-2031	$ 18,867	$ 978	$ 1,646

(12) COMMITMENTS AND CONTINGENCIES

We have the following power purchase and transmission services agreements, not including related party agreements, as of December 31, 2021 (see Note 13 for information on related party agreements):

Contract Type	Counterparty	Fuel Type	Quantity (MW)	Expiration Date
PPA	PacifiCorp	Coal	50	December 31, 2023
TSA [(a)]	PacifiCorp	N/A	50	December 31, 2023
PPA	Platte River Power Authority	Wind	12	September 30, 2029
PPA	Fall River Solar, LLC	Solar	80	Pending Completion [(b)]

(a) This is a firm point-to-point transmission service agreement providing the ability to deliver a maximum of 50 MW of capacity and associated energy.
(b) This agreement relates to a new solar facility currently being constructed and will expire 20 years after construction completion, which is expected by the end of 2022.

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

Contract Type	Counterparty	Fuel Type	2021	2020
PPA	PacifiCorp	Coal	$ 8,923	$ 5,897
TSA	PacifiCorp	N/A	$ 1,783	$ 1,776
PPA	Platte River Power Authority	Wind	$ 596	$ 715

Future Contractual Obligations

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

Minimum Payments required [(a)]		
2022	$	6,438
2023	$	6,203
2024	$	—
2025	$	—
2026	$	—
Thereafter	$	—

(a) This schedule does not reflect renewable energy PPA obligations since these agreements vary based on weather conditions.

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	
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.

(13) RELATED-PARTY TRANSACTIONS

Dividends to Parent

We paid dividends to our Parent of $14 million and $31 million in 2021 and 2020, respectively.

Money Pool 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 0.48% at December 31, 2021

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

	2021	2020
Money pool notes payable -- Notes Payable to Associated Companies (233)	$ 58,031	$ 90,703
Money pool interest payable -- Notes Payable to Associated Companies (233)	$ 19	$ 32

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

	2021	2020
Money pool interest expense, net (Accounts 419 and 430)	$ 277	$ 645

Notes payable to Parent

We had the following Notes payable to Parent balances as of December 31 (in thousands):

	2021	2020
Notes payable to Parent -- Notes Payable to Associated Companies (233) [(a)]	$ 114,400	$ 80,000
Interest payable on borrowings from associated companies (233)	$ 361	$ 293

(a) The Notes Payable to Parent balance at December 31, 2021, includes the unpaid portion of a $24 million Note to pay for the unprecedented incremental costs from Winter Storm Uri in the first quarter of 2021. We began recovering Winter Storm Uri incremental costs and carrying costs from customers in June 2021 and subsequently paid down a portion of the Note. See additional information in Note 7.

Interest expense relating to our Notes Payable to Parent for the year ended December 31, was as follows (in thousands):

	2021	2020
Notes payable to Parent interest expense -- Interest on Debt to Assoc. Companies (430)	$ 3,487	$ 2,171

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2021, and 2020, we were allocated $2.8 million and $0.4 million, respectively, of interest expense from BHC.

Other Agreements

We have the following agreements with affiliated entities:

- A Generation Dispatch Agreement with Wyoming Electric which requires us to purchase all of Wyoming Electric's excess energy. Under this same agreement, Wyoming Electric can also purchase off-system energy from us for the purpose of displacing some, or all, of the available energy from a higher-cost resource.
- A shared facilities agreement with Wyoming Electric and Black Hills Wyoming whereby each entity is charged for the use of assets located at the Gillette, Wyoming energy complex by the affiliate entity.
- 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.
- All-in requirements agreements with Wyodak Resources Development Corporation (WRDC mine), a related party, for the purchase of coal for use at Neil Simpson II, Wyodak Plant, and Wygen III.
- An intercompany agreement with Wyoming Electric to purchase 50% of the output they receive under a separate PPA with Happy Jack Wind Farm, LLC. Their agreement expires September 3, 2028 and provides up to 30 MW of wind energy from the wind farm located near Cheyenne, Wyoming.
- An intercompany agreement with Wyoming Electric to purchase 67% of the output they receive under a separate PPA with Silver Sage Wind Farm, LLC. Their agreement expires September 30, 2029 and provides up to 30 MW of wind energy from the wind farm located near Cheyenne, Wyoming.
- A Generation Dispatch Agreement with Wyoming Electric which requires us to purchase all of their excess energy. Under this same agreement, Wyoming Electric can also purchase off-system energy from us for the purpose of displacing some, or all, of the available energy from a higher-cost resource.
- 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.
- A Wygen III Ground Lease with WRDC mine expiring in 2050 with three automatic renewal terms of 20 years each.
- South Dakota Electric receives certain staffing and management services from BHSC for Cheyenne Prairie and Corriedale.

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:

	2021	2020
	(in thousands)	
Operating Revenues:		
Energy sold to Wyoming Electric	$ 2,574	$ 762
Rent from electric properties	$ 4,876	$ 3,957
Horizon Point shared facility revenue	$ 11,294	$ 11,360
Operating Expenses:		
Purchases from WRDC mine	$ 16,345	$ 16,863
Purchase of excess energy from Wyoming Electric	$ 1,996	$ 1,633
Purchase of renewable wind energy from Wyoming Electric - Happy Jack	$ 1,772	$ 2,266
Purchase of renewable wind energy from Wyoming Electric - Silver Sage	$ 3,160	$ 4,136
Gas transportation service agreement with Wyoming Electric for firm and interruptible gas transportation	$ 254	$ 311
Wygen III ground lease with WRDC mine	$ 1,016	$ 1,004

Related-party Corporate Support

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

	2021	2020
	(in thousands)	
Corporate support services and fees from Black Hills Service Company	$ 40,741	$ 45,299

(14) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2021	2020
	(in thousands)	
Cash (paid) refunded during the period for:		
Interest (net of amounts capitalized)	$ (25,927)	$ (24,493)
Income taxes	$ 8,893	$ (21,813)
Non-cash investing and financing activities:		
Accrued property, plant and equipment purchases at December 31	$ 11,204	$ 12,202

(15) SUBSEQUENT EVENT

Except as described below, there have been no events subsequent to December 31, 2021 which would require recognition in the financial statements or disclosure.

Transmission Service Agreements

On January 1, 2022, South Dakota Electric entered into a firm point-to-point transmission service agreement with MEAN that provides a maximum of 20 MW of capacity and associated energy. This agreement expires December 31, 2023.