THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 60 Approved
OMB No. 1902-0215
Expires 05/31/2019

FERC FINANCIAL REPORT
FERC FORM No. 60: Annual Report of Centralized Service Companies

This report is mandatory under the Public Utility Holding Company Act of 2005, Section 1270, Section 309 of the Federal Power Act and 18 C.F.R. § 366.23. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	**Year of Report**
Black Hills Utility Holdings, Inc.	**Dec 31,** 2018

GENERAL INSTRUCTIONS FOR FILING FERC FORM NO. 60

I. Purpose

Form No. 60 is an annual regulatory support requirement under 18 CFR 369.1for centralized service companies. The report is designed to collect financial information from centralized service companies subject to the jurisdiction of the Federal Energy Regulatory Commission. The report is considered to be a non-confidential public use form.

II. Who Must Submit

Unless the holding company system is exempted or granted a waiver by Commission rule or order pursuant to §§ 18 CFR 366.3 and 366.4 of this chapter, every centralized service company (see § 367.2) in a holding company system must prepare and file electronically with the Commission the FERC Form No. 60 then in effect pursuant to the General Instructions set out in this form.

III. How to Submit

Submit FERC Form No. 60 electronically through the Form No. 60 Submission Software. Retain one copy of each report for your files. For any resubmissions, submit the filing using the Form No. 60 Submission Software including a justification. Respondents must submit the Corporate Officer Certification electronically.

IV. When to Submit

Submit FERC Form No. 60 according to the filing date contained § 18 CFR 369.1 of the Commission's regulations.

V. Preparation

Prepare this report in conformity with the Uniform System of Accounts (18 CFR 367) (USof A). Interpret all accounting words and phrases in accordance with the USof A.

VI. Time Period

This report covers the entire calendar year.

VII. Whole Dollar Usage

Enter in whole numbers (dollars) only, except where otherwise noted. The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's amounts.

VIII. Accurateness

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IX. Applicability

For any page(s) that is not applicable to the respondent, enter "NONE," or "Not Applicable" in column (c) on the List of Schedules, page 2.

X. Date Format

Enter the month, day, and year for all dates. Use customary abbreviations. The "Resubmission Date" included in the header of each page is to be completed only for resubmissions (see III. above).

XI. Number Format

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by use of a minus sign.

XII. Required Entries

Do not make references to reports of previous years or to other reports instead of required entries, except as specifically authorized.

XIII. Prior Year References

Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the report of the previous year, or an appropriate explanation given as to why the different figures were used.

XIV. Where to Send Comments on Public Reporting Burden

The public reporting burden for the Form No. 60 collection of information is estimated to average 75 hours per response, including

- the time for reviewing instructions, searching existing data sources,
- gathering and maintaining the data-needed, and
- completing and reviewing the collection of information.

Send comments regarding these burden estimates or any aspect of this collection of information, including suggestions for reducing burden, to:

Federal Energy Regulatory Commission, (Attention: Information Clearance Officer, CIO),
888 First Street NE,
Washington, DC 20426
or by email to DataClearance@ferc.gov

And to:

Office of Information and Regulatory Affairs,
Office of Management and Budget, Washington, DC 20503 (Attention: Desk Office for the Federal Energy Regulatory Commission).
Comments to OMB should be submitted by email to: oira_submission@omb.eop.gov

No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. 3512(a)).

DEFINITIONS
I. Respondent -- The person, corporation, or other legal entity in whose behalf the report is made.

FERC FORM NO. 60
ANNUAL REPORT FOR SERVICE COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Black Hills Utility Holdings, Inc.	02 Year of Report Dec 31, 2018
03 Previous Name (If name changed during the year)	04 Date of Name Change / /
05 Address of Principal Office at End of Year (Street, City, State, Zip Code) 7001 Mt. Rushmore Rd. Rapid City, SD 57702	06 Name of Contact Person Kimberly Nooney
07 Title of Contact Person VP - Corporate Controller & Treasurer	08 Address of Contact Person 7001 Mt. Rushmore Rd, Rapid City, SD 57702
09 Telephone Number of Contact Person (605) 721-2370	10 E-mail Address of Contact Person kim.nooney@blackhillscorp.com
11 This Report is: (1) [X] An Original (2) [ ] A Resubmission	12 Resubmission Date (Month, Day, Year) / /
13 Date of Incorporation 06/09/2008	14 If Not Incorporated, Date of Organization / /

15 State or Sovereign Power Under Which Incorporated or Organized

SOUTH DAKOTA

16 Name of Principal Holding Company Under Which Reporting Company is Organized:

Black Hills Corporation

CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

17 Name of Signing Officer Kimberly Nooney	19 Signature of Signing Officer Kimberly Nooney	20 Date Signed (Month, Day, Year) 05/01/2019
18 Title of Signing Officer VP - Corporate Controller & Treasurer		

Name of Respondent Black Hills Utility Holdings, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2018

List of Schedules and Accounts

1. Enter in Column (c) the terms "None" or "Not Applicable" as appropriate, where no information or amounts have been reported for certain pages.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule I - Comparative Balance Sheet

1. Give balance sheet of the Company as of December 31 of the current and prior year.

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
1		**Service Company Property**			
2	101	Service Company Property	103	964,445,486	964,445,486
3	101.1	Property Under Capital Leases	103		
4	106	Completed Construction Not Classified			
5	107	Construction Work In Progress	103	11,692,955	4,624,149
6		Total Property (Total Of Lines 2-5)		976,138,441	969,069,635
7	108	Less: Accumulated Provision for Depreciation of Service Company Property	104	89,052	2,783
8	111	Less: Accumulated Provision for Amortization of Service Company Property			
9		Net Service Company Property (Total of Lines 6-8)		976,049,389	969,066,852
10		**Investments**			
11	123	Investment In Associate Companies	105	1,295,041,179	1,188,451,401
12	124	Other Investments	105		
13	128	Other Special Funds	105	10,000	10,000
14		Total Investments (Total of Lines 11-13)		1,295,051,179	1,188,461,401
15		**Current And Accrued Assets**			
16	131	Cash		13,270,791	5,304,755
17	134	Other Special Deposits			
18	135	Working Funds			
19	136	Temporary Cash Investments			
20	141	Notes Receivable		340,000,000	304,000,000
21	142	Customer Accounts Receivable			
22	143	Accounts Receivable		3,241,314	747,496
23	144	Less: Accumulated Provision for Uncollectible Accounts			50
24	146	Accounts Receivable From Associate Companies	106	222,082,896	218,682,143
25	152	Fuel Stock Expenses Undistributed	107		
26	154	Materials And Supplies		26,055	65,347
27	163	Stores Expense Undistributed	108		
28	165	Prepayments		7,924,856	7,891,248
29	171	Interest And Dividends Receivable			
30	172	Rents Receivable			
31	173	Accrued Revenues			
32	174	Miscellaneous Current and Accrued Assets			
33	175	Derivative Instrument Assets	109	126,500	54,405
34	176	Derivative Instrument Assets – Hedges			
35		Total Current and Accrued Assets (Total of Lines 16-34)		586,672,412	536,745,344
36		**Deferred Debits**			
37	181	Unamortized Debt Expense			
38	182.3	Other Regulatory Assets		9,768,587	32,998,162
39	183	Preliminary Survey And Investigation Charges			
40	184	Clearing Accounts		18,255	2,033
41	185	Temporary Facilities			
42	186	Miscellaneous Deferred Debits		184,754,935	187,693,268
43	188	Research, Development, or Demonstration Expenditures	110		
44	189	Unamortized loss on reacquired debt	111		
45	190	Accumulated Deferred Income Taxes		9,882,681	18,987,706
46		Total Deferred Debits (Total of Lines 37-45)		204,424,458	239,681,169
47		TOTAL ASSETS AND OTHER DEBITS (TOTAL OF LINES 9, 14, 35 and 46)		3,062,197,438	2,933,954,766

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule I - Comparative Balance Sheet (continued)

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
48		**Proprietary Capital**			
49	201	Common Stock Issued	201	1,000	1,000
50	204	Preferred Stock Issued	201		
51	211	Miscellaneous Paid-In-Capital	201	940,635,522	865,635,522
52	215	Appropriated Retained Earnings	201		
53	216	Unappropriated Retained Earnings	201	685,303,567	655,752,111
54	219	Accumulated Other Comprehensive Income	201	(139)	(375,657)
55		Total Proprietary Capital (Total of Lines 49-54)		1,625,939,950	1,521,012,976
56		**Long-Term Debt**			
57	223	Advances From Associate Companies	202	1,169,000,000	1,133,000,000
58	224	Other Long-Term Debt	202		
59	225	Unamortized Premium on Long-Term Debt			
60	226	Less: Unamortized Discount on Long-Term Debt-Debit			
61		Total Long-Term Debt (Total of Lines 57-60)		1,169,000,000	1,133,000,000
62		Other Non-current Liabilities			
63	227	Obligations Under Capital Leases-Non-current			
64	228.2	Accumulated Provision for Injuries and Damages		908,809	955,527
65	228.3	Accumulated Provision For Pensions and Benefits		851,600	23,920,629
66	230	Asset Retirement Obligations			
67		Total Other Non-current Liabilities (Total of Lines 63-66)		1,760,409	24,876,156
68		**Current and Accrued Liabilities**			
69	231	Notes Payable			
70	232	Accounts Payable		4,142,460	6,856,768
71	233	Notes Payable to Associate Companies	203	77,961,718	64,563,014
72	234	Accounts Payable to Associate Companies	203	59,409,653	42,875,112
73	236	Taxes Accrued		985,406	13,455,844
74	237	Interest Accrued			
75	241	Tax Collections Payable		632,836	519,937
76	242	Miscellaneous Current and Accrued Liabilities	203	11,359,634	9,899,811
77	243	Obligations Under Capital Leases – Current			
78	244	Derivative Instrument Liabilities		112,780	287,240
79	245	Derivative Instrument Liabilities – Hedges			
80		Total Current and Accrued Liabilities (Total of Lines 69-79)		154,604,487	138,457,726
81		**Deferred Credits**			
82	253	Other Deferred Credits		82	11,775
83	254	Other Regulatory Liabilities		12,531,663	21,441,872
84	255	Accumulated Deferred Investment Tax Credits			
85	257	Unamortized Gain on Reacquired Debt			
86	282	Accumulated deferred income taxes-Other property		22,728,320	21,639,555
87	283	Accumulated deferred income taxes-Other		75,632,527	73,514,706
88		Total Deferred Credits (Total of Lines 82-87)		110,892,592	116,607,908
89		**TOTAL LIABILITIES AND PROPRIETARY CAPITAL (TOTAL OF LINES 55, 61, 67, 80, AND 88)**		3,062,197,438	2,933,954,766

Name of Respondent Black Hills Utility Holdings, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018

FOOTNOTE DATA

Schedule Page: 101 Line No.: 5 Column: d

The increase is driven mainly by the following Projects: Meter Data Management System Boost ($1m), Customer Evolution for Success ($2.2m), and Bilateral Sofware Replacement ($2.2m).

Schedule Page: 101 Line No.: 20 Column: d

The $36m increase in associated company notes receivable is a result of intercompany financing related to the $525m note.

Schedule Page: 101 Line No.: 24 Column: d

BHUH Property and Accumulated Provision (lines 2, 4, 7 and 8) are allocated to subsidiaries. The associated receivable from the allocation is included in account 146 along with other intercompany receivables, including interest related to notes receivable from associated companies.

Schedule Page: 101 Line No.: 38 Column: d

Transferred $17m to Black Hills Service Company as a result of the annual actuarial valuation process each year end. Effective 1/1/2019, BHUH will no longer function as a centralized service company. All service company activities will be transferred to Black Hills Service Company. BHUH will remain as a holding company.

Schedule Page: 101 Line No.: 45 Column: d

Decrease is due to tax reform.

Schedule Page: 101 Line No.: 65 Column: d

Moved $10m from Black Hills Utility Holdings to Black Hills Service Company. Effective 1/1/2019, BHUH will no longer function as a centralized service company. All service company activities will be transferred to Black Hills Service Company. BHUH will remain as a holding company.

Schedule Page: 101 Line No.: 73 Column: d

Decrease is driven by tax appeal settlement.

Schedule Page: 101 Line No.: 83 Column: d

Decrease is due to tax reform.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule II - Service Company Property

1. Provide an explanation of Other Changes recorded in Column (f) considered material in a footnote.
2. Describe each construction work in progress on lines 18 through 30 in Column (b).

Line No.	Acct # (a)	Title of Account (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements or Sales (e)	Other Changes (f)	Balance at End of Year (g)
1	301	Organization	964,445,486				964,445,486
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights	646,324			(646,324)	
5	390	Structures and Improvements	8,427,948	132,476	100,586	(8,459,838)	
6	391	Office Furniture and Equipment	150,773,830	4,987,383	21,421,731	(134,339,482)	
7	392	Transportation Equipment	1,429,027	369,564	67,523	(1,731,068)	
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment	994,665	74,659	104,710	(964,614)	
10	395	Laboratory Equipment	180,931	100,427		(281,358)	
11	396	Power Operated Equipment	17,192			(17,192)	
12	397	Communications Equipment	464,368	3,026	77,734	(389,660)	
13	398	Miscellaneous Equipment	32,324			(32,324)	
14	399	Other Tangible Property	10,835,018	17,299,760	266,351	(27,868,427)	
15	399.1	Asset Retirement Costs					
16		**Total Service Company Property (Total of Lines 1-15)**	1,138,247,113	22,967,295	22,038,635	(174,730,287)	964,445,486
17	107	**Construction Work in Progress:**					
18		Accounting Accruals	242,998	1,702,103		(1,370,973)	574,128
19		AMI Hardware	472,158	1,750,572			2,222,730
20		Software Conversions	1,903,416	874,115		(126,945)	2,650,586
21		Office Furniture and Equipment	2,005,575	9,351,137		(5,116,868)	6,239,844
22		Tools, Shop, and Garage Equip		112,305		(106,640)	5,665
23		Vehicles		369,564		(369,564)	
24		Field Collection System		15,743,830		(15,743,830)	
25		Facilities	2	(17,188,452)		17,188,452	2
26							
27							
28							
29							
30							
31		**Total Account 107 (Total of Lines 18-30)**	4,624,149	12,715,174		(5,646,368)	11,692,955
32		**Total (Lines 16 and Line 31)**	1,142,871,261	35,682,469			976,138,441

Schedule Page: 103 Line No.: 1 Column: g

Plant acquisition is not allocated to the subsidiaries.

Schedule Page: 103 Line No.: 16 Column: c

The true beginning property balance is $964,445,486 that is not allocated. The other beginning balances in column c are the reversal of the entry which allocated all property at 12/31/17. Information is presented in this format to show the flow of activity and the amount of property allocated by BHUH.

Schedule Page: 103 Line No.: 31 Column: g

Construction Work in Progress is not allocated to the subsidiaries.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule III – Accumulated Provision for Depreciation and Amortization of Service Company Property

1. Provide an explanation of Other Charges in Column (f) considered material in a footnote.

Line No.	Account Number (a)	Description (b)	Balance at Beginning of Year (c)	Additions Charged To Account 403-403.1 404-405 (d)	Retirements (e)	Other Changes Additions (Deductions) (f)	Balance at Close of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements	2,490,162	200,616	100,586	(2,590,192)	
6	391	Office Furniture and Equipment	57,983,730	10,245,365	21,421,731	(46,807,364)	
7	392	Transportation Equipment	316,694	146,425	41,520	(421,599)	
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment	(573,050)	65,479	104,710	612,281	
10	395	Laboratory Equipment	(74,627)	11,633		62,994	
11	396	Power Operated Equipment	7,928	1,165		(9,093)	
12	397	Communications Equipment	(81,613)	22,420	77,734	136,927	
13	398	Miscellaneous Equipment	14,981	1,100		(16,081)	
14	399	Other Tangible Property	549,785	644,569	174,881	(930,421)	89,052
15	399.1	Asset Retirement Costs					
16		**Total**	60,633,990	11,338,772	21,921,162	(49,962,548)	89,052

FOOTNOTE DATA

Schedule Page: 104 Line No.: 16 Column: c

The beginning balances in column c are the reversal of the entry which allocated all property at 12/31/17. Information is presented in this format to show the flow of activity and the amount of property allocated by BHUH.

Schedule Page: 104 Line No.: 16 Column: g

The balance of RWIP (Retirement Work in Progress) remains on BHUH since this does not allocate out.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule IV – Investments

1. For other investments (Account 124) and other special funds (Account128), in a footnote state each investment separately, with description including the name of issuing company, number of shares held or principal investment amount.
2. For temporary cash investments (Account 136), list each investment separately in a footnote.
3. Investments less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	123	Investment In Associate Companies	1,188,451,401	1,295,041,179
2	124	Other Investments		
3	128	Other Special Funds	10,000	10,000
4	136	Temporary Cash Investments		
5		(Total of Lines 1-4)	1,188,461,401	1,295,051,179

FOOTNOTE DATA

Schedule Page: 105 Line No.: 3 Column: c

This line item holds the loss deposit and prefunding fee for Specialty Services, a third party administrator.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule V – Accounts Receivable from Associate Companies

1. List the accounts receivable from each associate company.
2. If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		Black Hills Power, Inc.	12,619,790	12,215,691
4		Cheyenne Light Fuel & Power Company	7,195,594	7,966,498
5		Black Hills Energy Kansas Gas	11,547,673	14,278,703
6		Black HIlls Energy Iowa Gas	19,099,717	22,853,270
7		Black Hillls Nebraska Gas Utility Company, LLC	20,667,095	24,938,807
8		Black HIlls Colorado Electric Utility Company, LP	15,480,539	15,634,913
9		Black Hills Colorado Gas Utility Company, LP	8,317,367	10,547,538
10		Black HIlls Northwest Wyoming Gas Utility Company, LC	511,921	584,636
11		Black Hills Shoshone Pipeline, LLC	662,761	661,062
12		Black Hills Energy Arkansas, Inc	27,066,548	20,514,447
13		Black Hills Colorado Gas Distribution	17,356,555	17,695,324
14		Black Hills Nebraska Gas Distribution	20,457,268	20,075,507
15		Black HIlls Wyoming Gas Distribution	13,805,912	10,421,378
16		Rocky Mountain Natural Gas, LLC	5,424,800	3,966,850
17		Black HIlls Energy Service Company	191,971	56,636
18		Black HIlls Gas II, Inc	26,413,863	26,413,863
19		Black Hills Holdings, LLC	10,320,868	10,320,868
20		Black Hills Gas Distribution, LLC	1,906	1,906
21		Black Hills Utility Money Pool Co	69,870	117,055
22				
23		Non Associate Companies:		
24		Black Hills Exploration and Production		107,098
25		Wyodak Resources Development Corp.		499
26		Black Hiills Wyoming, LLC	1,014	7,115
27		Black Hills Non-Regulated Holdings, LLC	647	40,024
28		Black HIlls Colorado IPP, LLC	94,037	838
29		Black Hills Corp	50,593	204,842
30		Black Hills Service Company, LLC	1,323,834	2,411,788
31		Black Hills Colorado Wind, LLC		45,740
32				
33				
34				
35				
36				
37				
38				
39				
40	**Total**		**218,682,143**	**222,082,896**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule VI – Fuel Stock Expenses Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company.
2. In a separate footnote, describe in a narrative the fuel functions performed by the service company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
3					
4					
5					
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40	**Total**				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule VII – Stores Expense Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed			
2		Associate Company:			
3					
4					
5					
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40	**Total**				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule VIII - Miscellaneous Current and Accrued Assets

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	174	**Miscellaneous Current and Accrued Assets**		
2		**Item List:**		
3		Derivatives	54,405	126,500
4				
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40	**Total**		**54,405**	**126,500**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule IX - Miscellaneous Deferred Debits

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	186	**Miscellaneous Deferred Debits**		
2		**Items List:**		
3		Deferred Gas Cost	98,312	
4		I/C Notes Recievable	185,000,000	185,000,000
5		Unrecovered Purchase Gas Cost	2,594,956	(245,065)
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40	**Total**		**187,693,268**	**184,754,935**

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Black Hills Utility Holdings, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

FOOTNOTE DATA

Schedule Page: 110 Line No.: 5 Column: d

The balance represents the unrecovered purchase gas costs, realized and unrealized; this account can have a debit or a credit balance, depending on our recovery position. (When the balance is in a credit position, it will be recassified to account 182.3, other regulatory assets).

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule X - Research, Development, or Demonstration Expenditures

1. Describe each material research, development, or demonstration project that incurred costs by the service corporation during the year. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Amount (c)
1	188	**Research, Development, or Demonstration Expenditures**	
2		**Project List:**	
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40	**Total**		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XI - Proprietary Capital

1. For miscellaneous paid-in capital (Account 211) and appropriate retained earnings (Account 215), classify amounts in each account, with a brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.
2. For the unappropriated retained earnings (Account 216), in a footnote, give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentages, amount of dividend, date declared and date paid.

Line No.	Account Number (a)	Title of Account (b)	Description (c)	Amount (d)
1	201	Common Stock Issued	Number of Shares Authorized	1,000,000
2			Par or Stated Value per Share	1.00
3			Outstanding Number of Shares	1,000
4			Close of Period Amount	1,000
5		Preferred Stock Issued	Number of Shares Authorized	
6			Par or Stated Value per Share	
7			Outstanding Number of Shares	
8			Close of Period Amount	
9	211	Miscellaneous Paid-In Capital		940,635,522
10	215	Appropriated Retained Earnings		
11	219	Accumulated Other Comprehensive Income		(139)
12	216	Unappropriated Retained Earnings	Balance at Beginning of Year	655,833,022
13			Net Income or (Loss)	167,972,076
14			Dividend Paid	(138,501,531)
15			Balance at Close of Year	685,303,567

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
Black Hills Utility Holdings, Inc.	(1) X An Original (2) __ A Resubmission	/ /	2018

FOOTNOTE DATA

Schedule Page: 201 Line No.: 12 Column: d

Beginning retained earnings was adjusted by $80,911 to reflect a cumulative accounting adjustment related to the Tax Cuts and Jobs Act enacted on December 22, 2017.

Schedule Page: 201 Line No.: 14 Column: d

Includes a non-cash dividend to BHC (parent company of BHUH) of $133,500,000.

Subsidiary Companies:	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**
Black Hills Kansas Gas Utility LLC	(5,000,000)	(500,000)		0
Black Hills Iowa Gas Utility LLC	(7,000,000)	0	0	0
Black Hills Nebraska Gas Utility LLC	(16,000,000)	0	0	0
Black Hills Colorado Electric Utility LP	(23,000,000)	(2,500,000)	(35,000,000)	0
Black Hills Colorado Gas Utility LP	0	0	0	(2,500,000)
Black Hills Energy service Company	(29,000,000)		(4,000,000)	(14,000,000)
	(80,000,000)	**(3,000,000)**	**(39,000,000)**	**(16,500,000)**
Total Non-Cash Distributions				(138,500,000)
Miscellaneous adjustments:				(1,530)
Non-Cash Distribution to BHC:				**$ (138,501,530)**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XII – Long Term Debt

1. For the advances from associate companies (Account 223), describe in a footnote the advances on notes and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation in Column (c).
2. For the deductions in Column (h), please give an explanation in a footnote.
3. For other long-term debt (Account 224), list the name of the creditor company or organization in Column (b).

Line No.	Account Number (a)	Title of Account (b)	Term of Obligation Class & Series of Obligation (c)	Date of Maturity (d)	Interest Rate (e)	Amount Authorized (f)	Balance at Beginning of Year (g)	Additions Deductions (h)	Balance at Close of Year (i)
1	223	Advances from Associate Companies							
2		Associate Company:							
3		$525 4.25% Note due 2023	Black Hills Co	08/30/2023	4.39700		489,000,000	36,000,000	525,000,000
4		$1.4B Financing	Black Hills Co	01/15/2026	4.28000		644,000,000		644,000,000
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11									
12									
13		TOTAL					1,133,000,000	36,000,000	1,169,000,000
14	224	Other Long-Term Debt							
15		List Creditor:							
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27									
28		TOTAL							

FOOTNOTE DATA

Schedule Page: 202 Line No.: 3 Column: e

Interest rate listed includes financing costs.

Schedule Page: 202 Line No.: 4 Column: b

This amount is made up of 4 tranches of debt, all of which are included under one Note Payable with the credit facility:

$400M 4.35% Note due 2033 - new in 2018

$300M 3.95% Note due 2026

$300M 4.20% Note due 2046

$400M 3.15% Note due 2027

The weighted average of this debt is used for the interest rate allocation.

Schedule Page: 202 Line No.: 4 Column: d

A note as of 1/1/2018 is in place through the maturity date of the $300M note, due in 2026.

Schedule Page: 202 Line No.: 4 Column: e

Interest rate listed includes applicable financing costs.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XIII – Current and Accrued Liabilities

1. Provide the balance of notes and accounts payable to each associate company (Accounts 233 and 234).
2. Give description and amount of miscellaneous current and accrued liabilities (Account 242). Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	233	Notes Payable to Associates Companies		
2		Total Notes Payment to Associate Companies	64,563,014	77,961,718
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24	234	Accounts Payable to Associate Companies		
25		Total Accounts Payable to Associate Companies	30,787,702	39,421,545
26				
27		Accounts Payable to Non-Associate Companies	12,087,410	19,988,108
28				
29				
30				
31				
32				
33				
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36				
37				
38				
39				
40				
41	242	Miscellaneous Current and Accrued Liabilities		
42		Total Miscellaneous and Accrued Liabilities	9,899,811	11,359,634
43				
44				
45				
46				
47				
48				
49				
50		(Total)	117,337,937	148,731,005

Schedule Page: 203 Line No.: 2 Column: d

	Balance at Beginning of Year	Balance at Close of Year
233 Notes Payable to Associate Companies		
BLACK HILLS UTILITY MONEY POOL CO	64,563,014	77,961,718
Total Notes Payable to Associate Companies	64,563,014	77,961,718

	Balance at Beginning of Year	Balance at Close of Year
234 Accounts Payable to Associate Companies		
BLACK HILLS POWER INC	606,703	1,780,025
CHEYENNE LIGHT FUEL AND POWER	584,366	1,165,237
BH KANSAS GAS UTILITY CO LLC	1,893,008	3,118,185
BH IOWA GAS UTILITY CO LLC	3,121,392	3,580,462
BH NEBRASKA GAS UTILITY CO LLC	3,144,028	3,758,206
BH COLORADO ELEC UTILITY CO LP	1,555,316	436,953
BH COLORADO GAS UTILITY CO LP	493,468	1,486,548
BH - NORTHWEST WYOMING	584,745	592,924
BH - SHOSHONE PIPELINE	42	929
BH ENERGY ARKANSAS	206,459	1,489,603
BH GAS DIST COLORADO	251,005	2,660,173
BH GAS DIST NEBRASKA	1,182,364	1,861,274
BH GAS DIST WYOMING	652,991	953,766
ROCKY MOUNTAIN NATURAL GAS	5,774	51,596
BH ENERGY SERVICES COMPANY	520,382	389,961
BLACK HILLS GAS HOLDINGS, LLC	15,831,065	15,831,065
BLACK HILLS GAS DISTRIBUTION, LLC	0	1,906
BLACK HILLS GAS, LLC	416	416
BLACK HILLS UTILITY MONEY POOL CO	154,178	262,315
	30,787,702	39,421,545

	Balance at Beginning of Year	Balance at Close of Year
234 Accounts Payable to Non Associate Companies		
WYODAK RESOURCES DEV CORP	5,611	655
BLACK HILLS WYOMING LLC	0	1,947
BLACK HILLS ELECTRIC GENERATION LLC	0	56,460
BLACK HILLS NON REG HOLDINGS LLC	0	49,670
BLACK HILLS COLORADO IPP, LLC	448	0
N780BH, LLC	12,008	72,530
BHEP PPLSOFT INTFC TO HORIZON	5,545	0
BLACK HILLS EXPLORATION & PRODUCTION INC	0	8,725
BLACK HILLS RESOURCES INC	0	104,251
BH PLATEAU PRODUCTION LLC	0	4,620
BLACK HILLS CORP	4,655,699	4,913,446
BH SERVICE COMPANY LLC	7,408,099	14,775,185

FOOTNOTE DATA

BHEP DISCONTINUED OPS	0	619
	12,087,410	19,988,108
234 Total	42,875,112	59,409,653

	Balance at Beginning of Year	Balance at Close of Year
242 Miscellaneous Current and Accrued Liabilities		
Misc Crnt & Accrued Liab	156,475	3,449
Gas contracts - Accrued Liab	672,219	1,061,404
Accrued Benefits Comp Abs	1,551,638	1,682,691
Accrued Incentive and Bonus	4,958,386	6,341,619
Accrued Payroll	1,086,928	1,510,522
SFAS 106 Current Portions	888,000	0
Accrued LT Performance Plan	119,184	170,472
Accrued Benefits 401K	466,981	589,475
	9,899,811	11,359,634
Total	117,337,936	148,731,005

Name of Respondent Black Hills Utility Holdings, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018

Schedule XIV- Notes to Financial Statements

1. Use the space below for important notes regarding the financial statements or any account thereof.
2. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year.
3. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year.
4. Furnish particulars as to any amounts recorded in Account 434, Extraordinary Income, or Account 435, Extraordinary Deductions.
5. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.
6. Describe the annual statement supplied to each associate service company in support of the amount of interest on borrowed capital and compensation for use of capital billed during the calendar year. State the basis for billing of interest to each associate company. If a ratio, describe in detail how ratio is computed. If more than one ratio explain the calculation. Report the amount of interest borrowed and/or compensation for use of capital billed to each associate company.

BHUH Notes to Financial Statements

These notes have been taken from the 10K general footnotes of the Black Hills Corporation. The notes included below are notes that are applicable to Black Hills Utility Holding Company.

Organization

Black Hills Utility Holdings, Inc. (the "Company," "BHUH") is a direct wholly-owned subsidiary of Black Hills Corporation ("BHC"), a public utility holding company subject to the regulation of the Public Utility Holding Company Act of 2005 ("PUHCA 2005").

Nature of Operations

BHUH provides services at cost. The cost of services are determined on a direct charge basis to the extent practicable and where not practicable, on a reasonable basis of allocation for indirect costs. The charges for services include no compensation for the use of capital.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Cash and Cash Equivalents and Restricted Cash

We consider all highly liquid investments with an original maturity of three months or less to be cash and cash equivalents. We maintain cash accounts for various specified purposes, which are classified as restricted cash. For purposes of the cash flow statements, we consider all highly liquid investments with original maturities of three months or less at the time of purchase to be cash and cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Electric and Gas Utilities business segments primarily consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and estimated unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Mining and Power Generation business segments consists of amounts due from sales of coal, electric energy and capacity.

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

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Revenue Recognition

Revenue is recognized in an amount that reflects the consideration we expect to receive in exchange for goods or services, when control of the promised goods or services is transferred to our customers. Our primary types of revenue contracts are:

- Regulated natural gas and electric utility services tariffs - Our utilities have regulated operations, as defined by ASC 980, that provide services to regulated customers under rates, charges, terms and conditions of service, and prices determined by the jurisdictional regulators designated for our service territories. Collectively, these rates, charges, terms and conditions are included in a tariff, which governs all aspects of the provision of our regulated services. Our regulated services primarily encompass single performance obligations material to the context of the contract for delivery of either commodity natural gas, commodity electricity, natural gas transportation or 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 regulator-empowered statute to establish contractual rates between the utility and its customers. All of our utilities' regulated sales are subject to regulatory-approved tariffs.

- Power sales agreements - Our Electric Utilities and Power Generation segments have long-term wholesale power sales agreements with other load-serving entities, including affiliates, for the sale of excess power from owned generating units. These agreements include a combination of "take or pay" arrangements, where the customer is obligated to pay for the energy regardless of whether it actually takes delivery, as well as "requirements only" arrangements, where the customer is only obligated to pay for the energy the customer needs. In addition to these long-term contracts, Black Hills 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.

- Coal supply agreements - Our Mining segment sells coal primarily under long-term contracts to utilities for use at their power generating plants, including affiliate electric utilities, and an affiliate non-regulated power generation entity. The contracts include a single promise to supply coal necessary to fuel the customers' facilities during the contract term. The transaction price is established in the coal supply agreements, including cost-based agreements with the affiliated regulated utilities, and is variable based on tons of coal delivered.

- Other non-regulated services - Our Gas and Electric Utilities segments also provide non-regulated services primarily comprised of appliance repair service and protection plans, electric and natural gas technical infrastructure construction and maintenance services, and in Nebraska and Wyoming, an unbundled natural gas commodity offering under the regulatory-approved Choice Gas Program. Revenue contracts for these services generally represent a single performance obligation with the price reflecting the standalone selling price stated in the agreement, and the revenue is variable based on the units delivered or services provided.

Materials, Supplies and Fuel

Materials and supplies represent parts and supplies for all of our business segments. Fuel - Electric Utilities represents oil, gas and coal on hand used to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are recorded using the weighted-average cost method and are valued at the lower-of-cost or net realizable value. The value of our Natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

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 and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets. We also classify our base or “cushion gas” as property, plant and equipment. Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.

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. Estimated removal costs associated with non-legal retirement obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, result in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, depreciation is computed on a unit-of-production methodology based on plant hours run.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized, but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life continue to be amortized over their estimated useful lives.

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Our annual goodwill impairment testing date is as of October 1, which aligns our testing date with our financial planning process.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. See Note 5 for additional business segment information.

Our goodwill impairment analysis includes an income approach and a market approach to estimate the fair value of our reporting units. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital, long-term earnings and merger multiples for comparable companies.

Asset Retirement Obligations

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income (Loss). The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations. For oil and gas liabilities classified as held for sale, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and prior to held-for-sale classification were depleted pursuant to the use of the full cost method of accounting.

Fair Value Measurements

Financial Instruments

We use the following fair value hierarchy for determining inputs for our financial instruments. Our financial instruments' 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 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.

Valuation Methodologies for Derivatives

The commodity contracts for the Electric and Gas Utilities, valued using the market approach, include exchange-traded futures, options, basis swaps and over-the-counter swaps (Level 2) for natural gas contracts. For exchange-traded futures, options and basis swap Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For over-the-counter swaps and options Level 2 assets and liabilities, fair value was derived from, or corroborated by, observable market pricing data. In addition, the fair value for the over-the-counter swaps and option derivatives, if material, include a CVA component. The CVA considers the fair value of the derivative and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Derivatives and Hedging Activities

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

In addition, certain derivatives contracts approved by regulatory authorities are either recovered or refunded through customer rates. Any changes in the fair value of these approved derivative contracts are deferred as a regulatory asset or regulatory liability pursuant to ASC 980.

We also have some derivatives that qualify for hedge accounting and are designated as cash flow hedges. The effective portion of the derivative gain or loss is deferred in AOCI and reclassified into earnings when the corresponding hedged transaction is recognized in earnings. Changes in the fair value of all other derivatives contracts are recognized in earnings.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty. We reflect the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterpart when a legal right of offset exists.

Deferred Financing Costs

Deferred financing costs are amortized over the estimated useful life of the related debt. Deferred financing costs are presented on the balance sheet as an adjustment to the related debt liabilities.

Regulatory Accounting

Our Electric Utilities and Gas Utilities follow accounting standards for regulated operations and reflect the effects of the numerous rate-making principles followed by the various state and federal agencies regulating the utilities. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which could require these net regulatory assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

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

<u>Deferred Energy and Fuel Cost Adjustments - Current</u> - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our Electric Utility 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. Our Electric Utilities file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions. The recovery period for these costs is less than a year.

<u>Deferred Gas Cost Adjustment</u> - Our regulated gas utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state utility commissions. The recovery period for these costs is less than a year.

<u>Gas Price Derivatives</u> - Our regulated utilities, as allowed or required by state utility commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. Gas price derivatives at December 31, 2018 are hedged over a maximum forward term of 2 years.

<u>Deferred Taxes on AFUDC</u> - 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 post-retirement benefit plans in regulatory assets rather than in AOCI, including costs being amortized from the Aquila and SourceGas Transactions.

Environmental - Environmental expenditures are costs associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 8 for additional details.

Loss on Reacquired Debt - Loss on reacquired debt is recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered currently deductible for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - South Dakota Electric and Colorado Electric received approval in 2014 for recovery of the remaining net book values and decommissioning costs of their decommissioned coal plants. In 2018, Arkansas Gas received approval to record decommissioning costs in a regulatory asset, with recovery to be determined in a future regulatory filing.

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

Deferred Energy and Gas Costs **-** Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

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

Cost of Removal - Cost of removal represents the estimated cumulative net provisions for future removal costs for which there is no legal obligation for removal included in depreciation expense.

Excess Deferred Income Taxes - The revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the TCJA was recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA.

Revenue Subject to Refund - Revenue subject to refund at December 31, 2018 represent revenue reserved as a result of the TCJA. See above "*TCJA Revenue Reserve*" under Revenue recognition for further disclosure.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain subsidiaries acquired file as a separate consolidated group. Where applicable, each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating expense adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use 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.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. See Notes 13 and 15 for additional information.

It is our policy to apply the flow-through method of accounting for investment tax credits. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. An exception to this general policy is the deferral method, which applies to our regulated businesses. 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 Income tax (expense) benefit on the Consolidated Statements of Income (Loss).

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 in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 15 for additional information.

RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

Market risk is the potential loss that may occur as a result of an adverse change in market price, rate or supply. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for several of our gas-fired generation assets, which include market fluctuations due to unpredictable factors such as weather, market speculation, pipeline constraints, and other factors that may impact natural gas supply and demand;

- Interest rate risk associated with our variable debt.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

Our credit exposure at December 31, 2018 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income (Loss) and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements) expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

Name of Respondent Black Hills Utility Holdings, Inc.	This Report is: (1) X An Original (2) _ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018

Schedule XIV- Notes to Financial Statements

For our regulated Utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2019 through December 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold. Effectiveness of our hedging position is evaluated at least quarterly.

FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2018 or 2017. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

FAIR VALUE OF FINANCIAL INSTRUMENTS

Cash and Cash Equivalents

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

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

REGULATORY MATTERS

TCJA revenue reserve

The TCJA signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21%. Effective January 1, 2018, the key impact of tax reform on existing utility revenues/tariffs established prior to tax reform, was primarily from the change in the federal tax rate from 35% to 21% affecting current income tax expense embedded in those tariffs. Black Hills has been collaborating with utility commissions in the states in which it provides utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We have received state utility commission approvals to provide the benefits of federal tax reform to utility customers in six states. We estimated and recorded a reserve to revenue of approximately $37 million during the year ended December 31, 2018. As of December 31, 2018, $19 million has been returned to customers.

Excess Deferred Income Taxes

As of December 31, 2018 and 2017, we have a regulatory liability associated with TCJA related items of approximately $311 million and $301 million, respectively. The majority of this regulatory liability relates to excess deferred taxes resulting from the remeasurement of deferred tax assets and liabilities in 2017. A majority of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets. As of December 31, 2018, the Company has amortized $2.1 million of this regulatory liability. The portion that was eligible for amortization under the average rate assumption method in 2018, but is awaiting resolution of the treatment of these amounts in future regulatory proceedings, has not been recognized and may be refunded in customer rates at any time in accordance with the resolution of pending or future regulatory proceedings. See Note 15 for more information.

EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor 401(k) retirement savings plans (the 401(k) Plans). Participants in the 401(k) Plans may elect to invest a portion of their eligible compensation in the 401(k) Plans up to the maximum amounts established by the IRS. The 401(k) Plans provide employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plans provide either a Company Matching Contribution or a Non-Elective Safe Harbor Contribution for all eligible participants, depending upon the Plan in which the employee participates. Certain eligible participants receive a Company Retirement Contribution based on the participant's age and years of service or a Company Discretionary Contribution, depending upon the pension plan in which the employee participates. Vesting of all Company contributions ranges from immediate vesting to graduated vesting at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

The SourceGas Retirement Savings Plan was merged into the Black Hills Corporation Retirement Savings Plan effective December 31, 2017. The plan design of the Black Hills Corporation 401(k) Plan will apply to all employees as of January 1, 2018.

Defined Benefit Pension Plan (Pension Plan)

We have one defined benefit pension plan, the Black Hills Retirement Plan (Pension Plan). The Pension Plan covers certain eligible employees of the Company. 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. Our Board of Directors has approved the Pension Plan's investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plan's beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan's benefit payment obligations. The Pension Plan's assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns, and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2018, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 29% to 37% return-seeking assets and 63% to 71% liability-hedging assets.

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

Account balances for Black Hills Utility Holdings, Inc's benefit plans were moved to Black Hills Service Company, LLC as of 12/31/2018 as a result of the annual actuarial valuation process each year end.

Supplemental Non-qualified Defined Benefit Plans

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

<u>Plan Assets</u>

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

Non-pension Defined Benefit Postretirement Healthcare Plans

BHC sponsors retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans for participating business units are pre-funded via VEBAs. Pre-65 retirees as well as a grandfathered group of post-65 Cheyenne Light, Fuel and Power ("CLFP") retirees and a grandfathered group of post-65 former SourceGas employees who retired prior to January 1, 2017 receive their retiree medical benefits through the Black Hills self-insured retiree medical plans.

Healthcare coverage for Medicare-eligible BHC and Black Hills Utility Holdings retirees is provided through an individual market healthcare exchange. Medicare-eligible SourceGas employees who retired after December 31, 2016 also receive retiree medical coverage through an individual market healthcare exchange.

<u>Plan Assets</u>

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Utility Holding and SourceGas Postretirement - AWG Plans provide for partial pre-funding via VEBAs and a Grantor Trust. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees located in the states of Arkansas, Kansas and Iowa. We do not pre-fund the Healthcare Plans for those employees outside Arkansas, Kansas and Iowa.

Name of Respondent Black Hills Utility Holdings, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018

Schedule XIV- Notes to Financial Statements

RELATED PARTY TRANSACTIONS

Parent and Affiliate Note Payables & Receivables — Financing for us and our utility subsidiaries is obtained at the parent level (BHC) and assigned to the utilities through intercompany notes. We are able to obtain more favorable financing terms by obtaining external debt at the parent level (BHC) than by obtaining external debt at the utility holding company or utility subsidiary level.

Non-cash Contribution to/from Parent — We record non-cash dividend to and non-cash contributions from our Parent company, which increases or decreases the utility money pool note receivable.

Accounts Receivable/Payable — We have accounts receivable balances related to transactions with affiliates.

BHUH - DISCONTINUATION AS SERVICE COMPANY

Effective January 1, 2019, BHUH will cease to function as a centralized service company. All service company activities previously performed by BHUH will be combined with the activities of Black Hills Service Company. This will be the final filing for BHUH on FERC Form 60.

Schedule XV- Comparative Income Statement

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
1		**SERVICE COMPANY OPERATING REVENUES**		
2	400	Service Company Operating Revenues	195,349,094	180,173,518
3		**SERVICE COMPANY OPERATING EXPENSES**		
4	401	Operation Expenses	128,930,522	115,125,467
5	402	Maintenance Expenses	14,890,573	15,363,328
6	403	Depreciation Expenses	11,994,934	11,945,985
7	403.1	Depreciation Expense for Asset Retirement Costs		
8	404	Amortization of Limited-Term Property		
9	405	Amortization of Other Property		
10	407.3	Regulatory Debits		
11	407.4	Regulatory Credits		
12	408.1	Taxes Other Than Income Taxes, Operating Income	189,713	321,950
13	409.1	Income Taxes, Operating Income	(1,145,011)	(13,414,943)
14	410.1	Provision for Deferred Income Taxes, Operating Income	54,280,164	57,602,259
15	411.1	Provision for Deferred Income Taxes – Credit , Operating Income	(51,017,833)	(82,432,600)
16	411.4	Investment Tax Credit, Service Company Property		
17	411.6	Gains from Disposition of Service Company Plant		
18	411.7	Losses from Disposition of Service Company Plant		
19	411.10	Accretion Expense		
20	412	Costs and Expenses of Construction or Other Services		
21	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work	3,349,828	2,848,057
22		TOTAL SERVICE COMPANY OPERATING EXPENSES (Total of Lines 4-21)	161,472,890	107,359,503
23		NET SERVICE COMPANY OPERATING INCOME (Total of Lines 2 less 22)	33,876,204	72,814,015
24		**OTHER INCOME**		
25	418.1	Equity in Earnings of Subsidiary Companies	170,091,308	98,268,381
26	419	Interest and Dividend Income	1,027,358	249,184
27	419.1	Allowance for Other Funds Used During Construction		
28	421	Miscellaneous Income or Loss	32,753	30,811
29	421.1	Gain on Disposition of Property	3,585	
30		**TOTAL OTHER INCOME (Total of Lines 25-29)**	171,155,004	98,548,376
31		**OTHER INCOME DEDUCTIONS**		
32	421.2	Loss on Disposition of Property		
33	425	Miscellaneous Amortization		
34	426.1	Donations	322,603	380,622
35	426.2	Life Insurance		
36	426.3	Penalties	150	640
37	426.4	Expenditures for Certain Civic, Political and Related Activities	156,094	265,481
38	426.5	Other Deductions	16,293	215,820
39		**TOTAL OTHER INCOME DEDUCTIONS (Total of Lines 32-38)**	495,140	862,563
40		**TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS**		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XV- Comparative Income Statement (continued)

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
41	408.2	Taxes Other Than Income Taxes, Other Income and Deductions		
42	409.2	Income Taxes, Other Income and Deductions		
43	410.2	Provision for Deferred Income Taxes, Other Income and Deductions		
44	411.2	Provision for Deferred Income Taxes – Credit, Other Income and Deductions		
45	411.5	Investment Tax Credit, Other Income Deductions		
46		**TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS (Total of Lines 41-45)**		
47		**INTEREST CHARGES**		
48	427	Interest on Long-Term Debt		
49	428	Amortization of Debt Discount and Expense		
50	429	(less) Amortization of Premium on Debt- Credit		
51	430	Interest on Debt to Associate Companies	36,772,976	34,172,205
52	431	Other Interest Expense	(208,984)	(186,042)
53	432	(less) Allowance for Borrowed Funds Used During Construction-Credit		
54		**TOTAL INTEREST CHARGES (Total of Lines 48-53)**	36,563,992	33,986,163
55		**NET INCOME BEFORE EXTRAORDINARY ITEMS (Total of Lines 23, 30, minus 39, 46, and 54)**	167,972,076	136,513,665
56		**EXTRAORDINARY ITEMS**		
57	434	Extraordinary Income		
58	435	(less) Extraordinary Deductions		
59		**Net Extraordinary Items (Line 57 less Line 58)**		
60	409.4	(less) Income Taxes, Extraordinary		
61		**Extraordinary Items After Taxes (Line 59 less Line 60)**		
62		**NET INCOME OR LOSS/COST OF SERVICE (Total of Lines 55-61)**	167,972,076	136,513,665

Schedule Page: 301 Line No.: 15 Column: c

Variance over last year is related to tax reform.

Schedule Page: 301 Line No.: 62 Column: c

BHUH does not have any true income as all of BHUH's cost is allocated to the subsidiairies. As a parent company, BHUH holds the earnings from it's subsidiairies, which is Equity in Earnings of Subsidiary Companies and the related income taxes.

418.1	Equity in Earnings of Subsidiary Companies	$	170,091,308
	(LESS)		
409.1	Income Taxes, Operating Income	$	(1,145,011)
410.1	Provision for Deferred Income Taxes, Operating Income	$	54,280,164
411.1	Provision for Deferred Income Taxes - Credit, Operating Income	$	(51,017,833)
	Allocation Reconciling Item	$	1,912
	Total	**$**	**167,972,076**

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies

1. Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
1	403-403.1	Depreciation Expense		11,727,385	11,727,385			
2	404-405	Amortization Expense						
3	407.3-407.4	Regulatory Debits/Credits – Net						
4	408.1-408.2	Taxes Other Than Income Taxes	(190)	189,903	189,713			
5	409.1-409.3	Income Taxes						
6	410.1-411.2	Provision for Deferred Taxes						
7	411.1-411.2	Provision for Deferred Taxes – Credit						
8	411.6	Gain from Disposition of Service Company Plant						
9	411.7	Losses from Disposition of Service Company Plant						
10	411.4-411.5	Investment Tax Credit Adjustment						
11	411.10	Accretion Expense						
12	412	Costs and Expenses of Construction or Other Services						
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies	541,986	6,691,743	7,233,729	40		40
14	418	Non-operating Rental Income						
15	418.1	Equity in Earnings of Subsidiary Companies						
16	419	Interest and Dividend Income	33,888	999,407	1,033,295			
17	419.1	Allowance for Other Funds Used During Construction						
18	421	Miscellaneous Income or Loss	83	33,775	33,858			
19	421.1	Gain on Disposition of Property		3,585	3,585			
20	421.2	Loss on Disposition Of Property						
21	425	Miscellaneous Amortization						
22	426.1	Donations	289,732	25,125	314,857	1,912		1,912
23	426.2	Life Insurance						
24	426.3	Penalties		150	150			
25	426.4	Expenditures for Certain Civic, Political and Related Activities	79,183	61,563	140,746	13,248		13,248
26	426.5	Other Deductions	19,372	(14,186)	5,186	10,608		10,608
27	427	Interest On Long-Term Debt		498	498			
28	428	Amortization of Debt Discount and Expense						
29	429	Amortization of Premium on Debt – Credit						
30	430	Interest on Debt to Associate Companies		36,772,976	36,772,976			
31	431	Other Interest Expense	12,010	(220,994)	(208,984)			
32	432	Allowance for Borrowed Funds Used During Construction						
33	500-509	Total Steam Power Generation Operation Expenses	106		106			
34	510-515	Total Steam Power Generation Maintenance Expenses	27,723		27,723			

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
35	517-525	Total Nuclear Power Generation Operation Expenses						
36	528-532	Total Nuclear Power Generation Maintenance Expenses						
37	535-540.1	Total Hydraulic Power Generation Operation Expenses						
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses						
39	546-550.1	Total Other Power Generation Operation Expenses	592		592			
40	551-554.1	Total Other Power Generation Maintenance Expenses	13,070		13,070	33,023		33,023
41	555-557	Total Other Power Supply Operation Expenses	10,004	135,276	145,280			
42	560	Operation Supervision and Engineering	498,909	1,496,718	1,995,627			
43	561.1	Load Dispatch-Reliability		2,181	2,181			
44	561.2	Load Dispatch-Monitor and Operate Transmission System	339,437	1,633,585	1,973,022			
45	561.3	Load Dispatch-Transmission Service and Scheduling	327,073	154,341	481,414			
46	561.4	Scheduling, System Control and Dispatch Services	308,557		308,557			
47	561.5	Reliability Planning and Standards Development	181,607	1,959,203	2,140,810			
48	561.6	Transmission Service Studies	3,310	533	3,843			
49	561.7	Generation Interconnection Studies	(11,271)		(11,271)			
50	561.8	Reliability Planning and Standards Development Services	634,992	4,398	639,390			
51	562	Station Expenses (Major Only)	31,072	1,793	32,865			
52	563	Overhead Line Expenses (Major Only)	312,915	122,716	435,631			
53	564	Underground Line Expenses (Major Only)						
54	565	Transmission of Electricity by Others (Major Only)						
55	566	Miscellaneous Transmission Expenses (Major Only)	510,639	342,703	853,342			
56	567	Rents						
57	567.1	Operation Supplies and Expenses (Nonmajor Only)						
58		Total Transmission Operation Expenses	3,137,240	5,718,171	8,855,411			
59	568	Maintenance Supervision and Engineering (Major Only)		200	200			
60	569	Maintenance of Structures (Major Only)		12,162	12,162			
61	569.1	Maintenance of Computer Hardware						
62	569.2	Maintenance of Computer Software						
63	569.3	Maintenance of Communication Equipment						
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant						
65	570	Maintenance of Station Equipment (Major Only)	62,614	19,548	82,162			
66	571	Maintenance of Overhead Lines (Major Only)	542,509	17,748	560,257			
67	572	Maintenance of Underground Lines (Major Only)						
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	1,048		1,048			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
69	574	Maintenance of Transmission Plant (Nonmajor Only)						
70		Total Transmission Maintenance Expenses	606,171	49,658	655,829			
71	575.1-575.8	Total Regional Market Operation Expenses						
72	576.1-576.5	Total Regional Market Maintenance Expenses						
73	580-589	Total Distribution Operation Expenses	2,567,635	2,166,879	4,734,514			
74	590-598	Total Distribution Maintenance Expenses	7,623,834	332,967	7,956,801			
75		Total Electric Operation and Maintenance Expenses	14,894,497	62,600,347	77,494,844	58,831		58,831
76	700-798	Production Expenses (Provide selected accounts in a footnote)	9,060		9,060			
77	800-813	Total Other Gas Supply Operation Expenses	5,937	(13,556)	(7,619)			
78	814-826	Total Underground Storage Operation Expenses	110,960	39,774	150,734			
79	830-837	Total Underground Storage Maintenance Expenses	32,649	103,571	136,220			
80	840-842.3	Total Other Storage Operation Expenses		17,222	17,222			
81	843.1-843.9	Total Other Storage Maintenance Expenses						
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses						
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses						
84	850	Operation Supervision and Engineering	273,906	613,408	887,314			
85	851	System Control and Load Dispatching.	12,093		12,093			
86	852	Communication System Expenses	4,847		4,847			
87	853	Compressor Station Labor and Expenses						
88	854	Gas for Compressor Station Fuel						
89	855	Other Fuel and Power for Compressor Stations						
90	856	Mains Expenses						
91	857	Measuring and Regulating Station Expenses						
92	858	Transmission and Compression of Gas By Others						
93	859	Other Expenses	1,354,418	69,961	1,424,379			
94	860	Rents	37,509	215	37,724			
95		Total Gas Transmission Operation Expenses	1,682,773	683,584	2,366,357			
96	861	Maintenance Supervision and Engineering	1,876	106,891	108,767			
97	862	Maintenance of Structures and Improvements	7,911	3,989	11,900			
98	863	Maintenance of Mains						
99	864	Maintenance of Compressor Station Equipment						
100	865	Maintenance of Measuring And Regulating Station Equipment						
101	866	Maintenance of Communication Equipment	8,753		8,753			
102	867	Maintenance of Other Equipment	1,111		1,111			
103		Total Gas Transmission Maintenance Expenses	19,651	110,880	130,531			
104	870-881	Total Distribution Operation Expenses	2,679,851	5,284,903	7,964,754			

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
105	885-894	Total Distribution Maintenance Expenses	50,022	1,331,670	1,381,692			
106		Total Natural Gas Operation and Maintenance Expenses	4,590,903	7,558,048	12,148,951			
107	901	Supervision	14,360	1,385,617	1,399,977			
108	902	Meter reading expenses	266	94,283	94,549			
109	903	Customer records and collection expenses	5,710,866	20,236,904	25,947,770			
110	904	Uncollectible accounts	6,545,578		6,545,578			
111	905	Miscellaneous customer accounts expenses	30,980	474,662	505,642			
112	906	Total Customer Accounts Operation Expenses	12,302,050	22,191,466	34,493,516			
113	907	Supervision	30,878	447,427	478,305			
114	908	Customer assistance expenses	990,376	1,049,471	2,039,847			
115	909	Informational And Instructional Advertising Expenses	16,805	21,675	38,480			
116	910	Miscellaneous Customer Service And Informational Expenses	11,936	39,161	51,097			
117		Total Service and Informational Operation Accounts	1,049,995	1,557,734	2,607,729			
118	911	Supervision	3,873	4,510	8,383			
119	912	Demonstrating and Selling Expenses	507,829	277,053	784,882			
120	913	Advertising Expenses	107,301	191,530	298,831			
121	916	Miscellaneous Sales Expenses		2,786	2,786			
122		Total Sales Operation Expenses	619,003	475,879	1,094,882			
123	920	Administrative and General Salaries	10,423,765	31,503,789	41,927,554	466,198		466,198
124	921	Office Supplies and Expenses	(3,770,237)	5,589,619	1,819,382	148,772		148,772
125	923	Outside Services Employed	455,498	5,083,345	5,538,843	206,292		206,292
126	924	Property Insurance		1,119	1,119			
127	925	Injuries and Damages		1,465,935	1,465,935			
128	926	Employee Pensions and Benefits		(46,613)	(46,613)			
129	928	Regulatory Commission Expenses	3,133,811		3,133,811			
130	930.1	General Advertising Expenses	46,066	52,316	98,382	658		658
131	930.2	Miscellaneous General Expenses	30,916	1,119,802	1,150,718	3,330		3,330
132	931	Rents	(57)	6,989,258	6,989,201			
133		Total Administrative and General Operation Expenses	10,319,762	51,758,570	62,078,332	825,250		825,250
134	935	Maintenance of Structures and Equipment	39,690	4,507,069	4,546,759			
135		Total Administrative and General Maintenance Expenses	24,330,500	80,490,718	104,821,218	825,250		825,250
136		Total Cost of Service	43,815,900	150,649,113	194,465,013	884,081		884,081

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
1	403-403.1	Depreciation Expense		11,727,385	11,727,385
2	404-405	Amortization Expense			
3	407.3-407.4	Regulatory Debits/Credits – Net			
4	408.1-408.2	Taxes Other Than Income Taxes	(190)	189,903	189,713
5	409.1-409.3	Income Taxes			
6	410.1-411.2	Provision for Deferred Taxes			
7	411.1-411.2	Provision for Deferred Taxes – Credit			
8	411.6	Gain from Disposition of Service Company Plant			
9	411.7	Losses from Disposition of Service Company Plant			
10	411.4-411.5	Investment Tax Credit Adjustment			
11	411.10	Accretion Expense			
12	412	Costs and Expenses of Construction or Other Services			
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies	542,026	6,691,743	7,233,769
14	418	Non-operating Rental Income			
15	418.1	Equity in Earnings of Subsidiary Companies			
16	419	Interest and Dividend Income	33,888	999,407	1,033,295
17	419.1	Allowance for Other Funds Used During Construction			
18	421	Miscellaneous Income or Loss	83	33,775	33,858
19	421.1	Gain on Disposition of Property		3,585	3,585
20	421.2	Loss on Disposition Of Property			
21	425	Miscellaneous Amortization			
22	426.1	Donations	291,644	25,125	316,769
23	426.2	Life Insurance			
24	426.3	Penalties		150	150
25	426.4	Expenditures for Certain Civic, Political and Related Activities	92,431	61,563	153,994
26	426.5	Other Deductions	29,980	(14,186)	15,794
27	427	Interest On Long-Term Debt		498	498
28	428	Amortization of Debt Discount and Expense			
29	429	Amortization of Premium on Debt – Credit			
30	430	Interest on Debt to Associate Companies		36,772,976	36,772,976
31	431	Other Interest Expense	12,010	(220,994)	(208,984)
32	432	Allowance for Borrowed Funds Used During Construction			
33	500-509	Total Steam Power Generation Operation Expenses	106		106
34	510-515	Total Steam Power Generation Maintenance Expenses	27,723		27,723

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
35	517-525	Total Nuclear Power Generation Operation Expenses			
36	528-532	Total Nuclear Power Generation Maintenance Expenses			
37	535-540.1	Total Hydraulic Power Generation Operation Expenses			
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses			
39	546-550.1	Total Other Power Generation Operation Expenses	592		592
40	551-554.1	Total Other Power Generation Maintenance Expenses	46,093		46,093
41	555-557	Total Other Power Supply Operation Expenses	10,004	135,276	145,280
42	560	Operation Supervision and Engineering	498,909	1,496,718	1,995,627
43	561.1	Load Dispatch-Reliability		2,181	2,181
44	561.2	Load Dispatch-Monitor and Operate Transmission System	339,437	1,633,585	1,973,022
45	561.3	Load Dispatch-Transmission Service and Scheduling	327,073	154,341	481,414
46	561.4	Scheduling, System Control and Dispatch Services	308,557		308,557
47	561.5	Reliability Planning and Standards Development	181,607	1,959,203	2,140,810
48	561.6	Transmission Service Studies	3,310	533	3,843
49	561.7	Generation Interconnection Studies	(11,271)		(11,271)
50	561.8	Reliability Planning and Standards Development Services	634,992	4,398	639,390
51	562	Station Expenses (Major Only)	31,072	1,793	32,865
52	563	Overhead Line Expenses (Major Only)	312,915	122,716	435,631
53	564	Underground Line Expenses (Major Only)			
54	565	Transmission of Electricity by Others (Major Only)			
55	566	Miscellaneous Transmission Expenses (Major Only)	510,639	342,703	853,342
56	567	Rents			
57	567.1	Operation Supplies and Expenses (Nonmajor Only)			
58		Total Transmission Operation Expenses	3,137,240	5,718,171	8,855,411
59	568	Maintenance Supervision and Engineering (Major Only)		200	200
60	569	Maintenance of Structures (Major Only)		12,162	12,162
61	569.1	Maintenance of Computer Hardware			
62	569.2	Maintenance of Computer Software			
63	569.3	Maintenance of Communication Equipment			
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant			
65	570	Maintenance of Station Equipment (Major Only)	62,614	19,548	82,162
66	571	Maintenance of Overhead Lines (Major Only)	542,509	17,748	560,257
67	572	Maintenance of Underground Lines (Major Only)			
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	1,048		1,048

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
Black Hills Utility Holdings, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2018

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
69	574	Maintenance of Transmission Plant (Nonmajor Only)			
70		Total Transmission Maintenance Expenses	606,171	49,658	655,829
71	575.1-575.8	Total Regional Market Operation Expenses			
72	576.1-576.5	Total Regional Market Maintenance Expenses			
73	580-589	Total Distribution Operation Expenses	2,567,635	2,166,879	4,734,514
74	590-598	Total Distribution Maintenance Expenses	7,623,834	332,967	7,956,801
75		Total Electric Operation and Maintenance Expenses	14,953,328	62,600,347	77,553,675
76	700-798	Production Expenses (Provide selected accounts in a footnote)	9,060		9,060
77	800-813	Total Other Gas Supply Operation Expenses	5,937	(13,556)	(7,619)
78	814-826	Total Underground Storage Operation Expenses	110,960	39,774	150,734
79	830-837	Total Underground Storage Maintenance Expenses	32,649	103,571	136,220
80	840-842.3	Total Other Storage Operation Expenses		17,222	17,222
81	843.1-843.9	Total Other Storage Maintenance Expenses			
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses			
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses			
84	850	Operation Supervision and Engineering	273,906	613,408	887,314
85	851	System Control and Load Dispatching.	12,093		12,093
86	852	Communication System Expenses	4,847		4,847
87	853	Compressor Station Labor and Expenses			
88	854	Gas for Compressor Station Fuel			
89	855	Other Fuel and Power for Compressor Stations			
90	856	Mains Expenses			
91	857	Measuring and Regulating Station Expenses			
92	858	Transmission and Compression of Gas By Others			
93	859	Other Expenses	1,354,418	69,961	1,424,379
94	860	Rents	37,509	215	37,724
95		Total Gas Transmission Operation Expenses	1,682,773	683,584	2,366,357
96	861	Maintenance Supervision and Engineering	1,876	106,891	108,767
97	862	Maintenance of Structures and Improvements	7,911	3,989	11,900
98	863	Maintenance of Mains			
99	864	Maintenance of Compressor Station Equipment			
100	865	Maintenance of Measuring And Regulating Station Equipment			
101	866	Maintenance of Communication Equipment	8,753		8,753
102	867	Maintenance of Other Equipment	1,111		1,111
103		Total Gas Transmission Maintenance Expenses	19,651	110,880	130,531
104	870-881	Total Distribution Operation Expenses	2,679,851	5,284,903	7,964,754

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
105	885-894	Total Distribution Maintenance Expenses	50,022	1,331,670	1,381,692
106		Total Natural Gas Operation and Maintenance Expenses	4,590,903	7,558,048	12,148,951
107	901	Supervision	14,360	1,385,617	1,399,977
108	902	Meter reading expenses	266	94,283	94,549
109	903	Customer records and collection expenses	5,710,866	20,236,904	25,947,770
110	904	Uncollectible accounts	6,545,578		6,545,578
111	905	Miscellaneous customer accounts expenses	30,980	474,662	505,642
112	906	Total Customer Accounts Operation Expenses	12,302,050	22,191,466	34,493,516
113	907	Supervision	30,878	447,427	478,305
114	908	Customer assistance expenses	990,376	1,049,471	2,039,847
115	909	Informational And Instructional Advertising Expenses	16,805	21,675	38,480
116	910	Miscellaneous Customer Service And Informational Expenses	11,936	39,161	51,097
117		Total Service and Informational Operation Accounts	1,049,995	1,557,734	2,607,729
118	911	Supervision	3,873	4,510	8,383
119	912	Demonstrating and Selling Expenses	507,829	277,053	784,882
120	913	Advertising Expenses	107,301	191,530	298,831
121	916	Miscellaneous Sales Expenses		2,786	2,786
122		Total Sales Operation Expenses	619,003	475,879	1,094,882
123	920	Administrative and General Salaries	10,889,963	31,503,789	42,393,752
124	921	Office Supplies and Expenses	(3,621,465)	5,589,619	1,968,154
125	923	Outside Services Employed	661,790	5,083,345	5,745,135
126	924	Property Insurance		1,119	1,119
127	925	Injuries and Damages		1,465,935	1,465,935
128	926	Employee Pensions and Benefits		(46,613)	(46,613)
129	928	Regulatory Commission Expenses	3,133,811		3,133,811
130	930.1	General Advertising Expenses	46,724	52,316	99,040
131	930.2	Miscellaneous General Expenses	34,246	1,119,802	1,154,048
132	931	Rents	(57)	6,989,258	6,989,201
133		Total Administrative and General Operation Expenses	11,145,012	51,758,570	62,903,582
134	935	Maintenance of Structures and Equipment	39,690	4,507,069	4,546,759
135		Total Administrative and General Maintenance Expenses	25,155,750	80,490,718	105,646,468
136		Total Cost of Service	44,699,981	150,649,113	195,349,094

FOOTNOTE DATA

Schedule Page: 304 Line No.: 13 Column: e

The following activity is included in account 416:

415000 MERCHANDISE REVENUES	1,106
416000 EXP MERCH JOBBING & CONTRACT	12,602
417100 NONUTILITY EXPENSES - COS	17,762
417101 NONUTILITY EXP - OTHER O&M	4,134,478
417158 NONUTILITY OPS EXPENSE OTHER	47,695
417160 NONUTILITY SELLING EXPENSE	1,195,180
417161 NONUTILITY ADMIN & GENERAL	1,142,519
417162 ADMIN AND GEN-EMPL BENEFITS	149,054
417165 EXP FOR UNCOLLECT ACCT NONREG	268,645
417180 NONUTILITY DEPRECIATION EXP	264,687
Total	7,233,729

Schedule Page: 304 Line No.: 40 Column: e

The following activity is included in 551-554:

552000 OTHR GEN MAINT OF STRUCTURES	489
553000 OTHR GEN MAINT OF GENR PLANT	12,581
569000 TRANS MAINT OF STRUCTURES	33,023
Total	46,093

Schedule Page: 304 Line No.: 77 Column: e

The following activity is included in 800-813:

804000 NATURAL GAS CITY GATE PURCHASE	205,737
454000 RENT FROM ELECTRIC PROPERTY	11,903
488000 MISC SERVICE REV GAS	(5,966)
805200 FINANCIAL GAS COST ADJ	(205,737)
812000 GAS USED FOR OTHER UTILITY OPS	(13,556)
Total	(7,619)

Schedule Page: 304 Line No.: 124 Column: e

The following activity is included in 921:

921000 OFFICE SUPPLIES & EXPENSE	6,244,607

FOOTNOTE DATA

922000 ADMIN EXP TRANS CREDIT	(4,276,453)
Total	1,968,154

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
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Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Black Hills Power Inc	9,766,549	15,056,070		24,822,619
2	Cheyenne Light Fuel and Power	3,874,150	8,209,509		12,083,659
3	Black Hills Kansas Utility Company LLC	2,380,078	8,103,989		10,484,067
4	Black Hills Iowa Gas Utility Company LLC	3,177,295	10,596,033		13,773,328
5	Black Hills Nebraska Gas Utility Company LLC	2,081,231	13,891,012		15,972,243
6	Black Hills Colorado Elec Utility	8,456,849	13,975,893		22,432,742
7	Black HIlls Colorado Gas Utility Company LP	1,263,542	5,225,228		6,488,770
8	Black HIlls Northwest Wyoming	295,534	561,925		857,459
9	Black Hills Shoshone Pipeline	35,064	4,097		39,161
10	Black Hills Energy Arkansas	5,071,385	28,144,858		33,216,243
11	Black Hills Gas Distribution Colorado	1,534,153	13,589,062		15,123,215
12	Black Hills Gas Distribution Nebraska	2,188,904	15,582,430		17,771,334
13	Black Hills Gas Distribution Wyoming	2,828,534	12,173,879		15,002,413
14	Rocky Mountain Natural Gas	838,962	4,890,766		5,729,728
15	Black Hills Energy Service Company	23,670	644,362		668,032
16	Black Hills Gas Holdings LLC				
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18					
19					
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40	**Total**	**43,815,900**	**150,649,113**		**194,465,013**

Name of Respondent Black Hills Utility Holdings, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2018

Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)

1. For services rendered to nonassociate companies (Account 458), list all of the nonassociate companies. In a footnote, describe the services rendered to each respective nonassociate company.

Line No.	Name of Non-associate Company (a)	Account 458.1 Direct Costs Charged (b)	Account 458.2 Indirect Costs Charged (c)	Account 458.3 Compensation For Use of Capital (d)	Account 458.4 Excess or Deficiency on Servicing Non-associate Utility Companies (e)	Total Amount Billed (f)
1	Black Hills Corp	19,408				19,408
2	Black HIlls Service Company	830,443				830,443
3	Wyodak Resources Dev Company	4,121				4,121
4	Black Hills Wyoming LLC	16,207				16,207
5	Black HIlls Electric Generation LLC					
6	Black Hills Colorado IPP LLC	13,902				13,902
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40	**Total**	**884,081**				**884,081**

Schedule XIX - Miscellaneous General Expenses - Account 930.2

1. Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Amounts less than $50,000 may be grouped showing the number of items and the total for the group.
2. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

Line No.	Title of Account (a)	Amount (b)
1	Labor Straight Time Non-Union	124,066
2	Industry Association Dues for Company Membership	624,137
3	Market Research Data Subscription	75,651
4	Director Retainers & Fees	184,162
5	Other	194,968
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40	**Total**	**1,202,984**

Name of Respondent Black Hills Utility Holdings, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018

Schedule XX - Organization Chart

1. Provide a graphical presentation of the relationships and inter relationships within the service company that identifies lines of authority and responsibility in the organization.

BLACK HILLS UTILITY HOLDINGS, INC.
LIST OF OFFICERS AND DIRECTORS

OFFICER	TITLE
David R. Emery	Chairman and Chief Executive Officer
Linden R. Evans	President and Chief Operating Officer
Richard W. Kinzley	Senior Vice President and Chief Financial Officer
Brian G. Iverson	Senior Vice President and General Counsel (also Chief Compliance Officer and Assistant Secretary)
Scott A. Buchholz	Senior Vice President – Chief Information Officer
Jennifer C. Landis	Senior Vice President – Chief Human Resources Officer
Roxann R. Basham	Vice President – Governance and Corporate Secretary
Esther J. Newbrough	Vice President and Chief Risk Officer **(1)**
Kimberly F. Nooney	Vice President – Corporate Controller and Treasurer **(2)**
Donna E. Genora	Vice President – Tax **(5)**
Amy K. Koenig	Assistant Corporate Secretary
Stuart A. Wevik	Group Vice President – Electric Utilities
Ivan Vancas	Group Vice President – Natural Gas Utilities
Kyle D. White	Vice President – Regulatory Strategy
Marne M. Jones	Vice President – Regulatory and Finance **(4)**
Perry S. Krush	Vice President – Facilities
Karen Beachy	Vice President – Growth and Strategy **(6)**
Mark L. Lux	Vice President – Energy Innovation **(7)**
Marc Ostrem	Vice President – Power Delivery, Safety and Environmental **(8)**
Mark E. Stege	Vice President – Customer Service
Jodi Culp	Vice President – Gas Asset Optimization
John A. Hill, Jr.	Vice President – Gas Engineering
BOARD OF DIRECTORS	
David R. Emery	Chairman
Linden R. Evans	Director
Richard W. Kinzley	Director

Name of Respondent Black Hills Utility Holdings, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018

Schedule XX - Organization Chart

Brian G. Iverson Director

(1) Esther Newbrough's title changed from Vice President – Corporate Controller to Vice President and Chief Risk Officer effective June 6, 2018

(2) Kimberly F. Nooney's title changed from Vice President – Treasurer to Vice President – Corporate Controller and Treasurer effective June 6, 2018

(3) Jeffrey B. Berzina was removed as Vice President – Strategic Planning and Development effective June 6, 2018

(4) Marne M. Jones' title changed from Vice President – Regulatory to Vice President – Regulatory and Finance effective June 6, 2018

(5) Donna E. Genora was appointed to replace Melinda Lee Watkins as Vice President – Tax effective September 28, 2018

(6) Karen Beachy's title changed from Vice President – Supply Chain to Vice President – Growth and Strategy effective October 15, 2018

(7) Mark Lux's title changed from Vice President – Power Generation, Safety and Environmental to Vice President – Energy Innovation effective October 15, 2018

(8) Marc Ostrem was appointed Vice President – Power Delivery, Safety and Environmental effective October 15, 2018

Name of Respondent Black Hills Utility Holdings, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2018

Schedule XXI - Methods of Allocation

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator.
2. Include any other allocation methods used to allocate costs.

Any asset ratios and employee and customer count ratios are calculated as of period-end dates, while revenue and expense ratios are calculated for twelve months ended as of period-end dates.

Asset Cost Ratio – Based on the net cost of assets as of September 30th for the prior year, the numerator of which is for an applicable operating company and the denominator of which is all applicable operating companies. Assets are limited to property, plant, and equipment, and include construction or work in process less accumulated depreciation, depletion and amortization (compliance with GAAP).

No departments utilize this ratio, but it is a component in the Blended Ratio.

Gross Margin Ratio – Based on the total gross margin for the trailing twelve months ending September 30th, the numerator of which is for an applicable operating company and the denominator of which is for all applicable operating companies. Gross margin is defined as revenue less cost of sales. Certain intercompany transactions may be excluded from gross margin if they would not have occurred if the revenue relationship was with a third party instead of a related party.

No departments utilize this ratio, but it is a component in the Blended Ratio.

Payroll Dollar Ratio –Based on the total payroll dollars for the trailing twelve months ending September 30th, the numerator of which is the direct payroll charges from all BHC subsidiaries charging an applicable operating company and the denominator of which is for all applicable operating companies. Payroll dollars include all bonuses and compensation paid to employees, but do not include items that are only included on an employee's W-2 for gross-up and income tax purposes, such as life insurance premiums of $50,000.

No departments utilize this ratio, but it is a component in the Blended Ratio.

Blended Ratio – A composite ratio comprised of an average of the Asset Cost Ratio, Payroll Dollar Ratio and the

Gross Margin Ratio. These factors are equally weighted. This factor is sometimes referred to as the general allocation factor.

There are currently several variations of the Blended ratio that are specific to the segment that are appropriate for which charges are being allocated. For example, charges for electric engineering department labor would utilize an electric blended ratio whereby no allocations would be charged to a gas utility.

BHUH is utilizing the following segment variations and additional variations may be added if additional product lines are added or in the event that additional segmentation is deemed appropriate to most effectively allocate costs from a specific department

All Blended

Electric Blended

Gas Blended

BHE Blended

BHGD Blended

Departments that utilize this ratio include BHUH Benefits Loading, Revenue and COGS, BHUH Accounting Accruals, All Blended Assets, Electric Blended Assets, Gas Blended Assets, Asset Planning and Data Management, Design Engineering Gas, Pipeline Safety and Compliance Support, Electric Engineering Services, Regulatory, HR Rotation Program, Executive Management Utilities, Business Development, Power Supply and Renewables, Electric Ops Communications, and Pipeline and System Integrity.

Any department at Black Hills Corp that appropriately charges a BHUH operating unit but is not part of the predefined allocation design will also utilize the Blended Allocator Ratio. For example if a BHSC IT department provides maintenance on the SCADA system supporting the regulated electric companies they would charge BHUH operating unit 201900 and these costs would be allocated using the Blended Ratio across the regulated electric companies.

Customer Count Ratio – Based on the number of customers as of September 30th for the prior year, the numerator of which is for an applicable operating company and the denominator of which is for all applicable operating companies.

There are currently several variations of the Customer Count ratio that are specific to the type of customers that are appropriate to the department for which charges are being allocated. For example a department that supports gas engineering would be allocated based on gas customers only whereas a general customer service department would be allocated based on total customers.

BHUH is utilizing the following customer counts to calculate customer count ratios additional variations may be added if additional product lines are added or in the event that additional segmentation of customers are deemed appropriate to most effectively allocate costs from a specific department

Customers

Electric Customers

Gas Customers

BHE Customers

BHGD Customers

Non-Regulated Customers

Departments that utilize these ratios include Gas Asset Optimization, Computer Aided Dispatch, Regulated Generation Assets, Customer Blended Assets, Technical Training, GIS Support, Gas Measuring, Community Affairs, Electric Meter Services, Customer Serv Call Centers, Customer Serv Supp,, Field Resource Center, Repair Business Marketing, and Energy Efficiency/DSM.

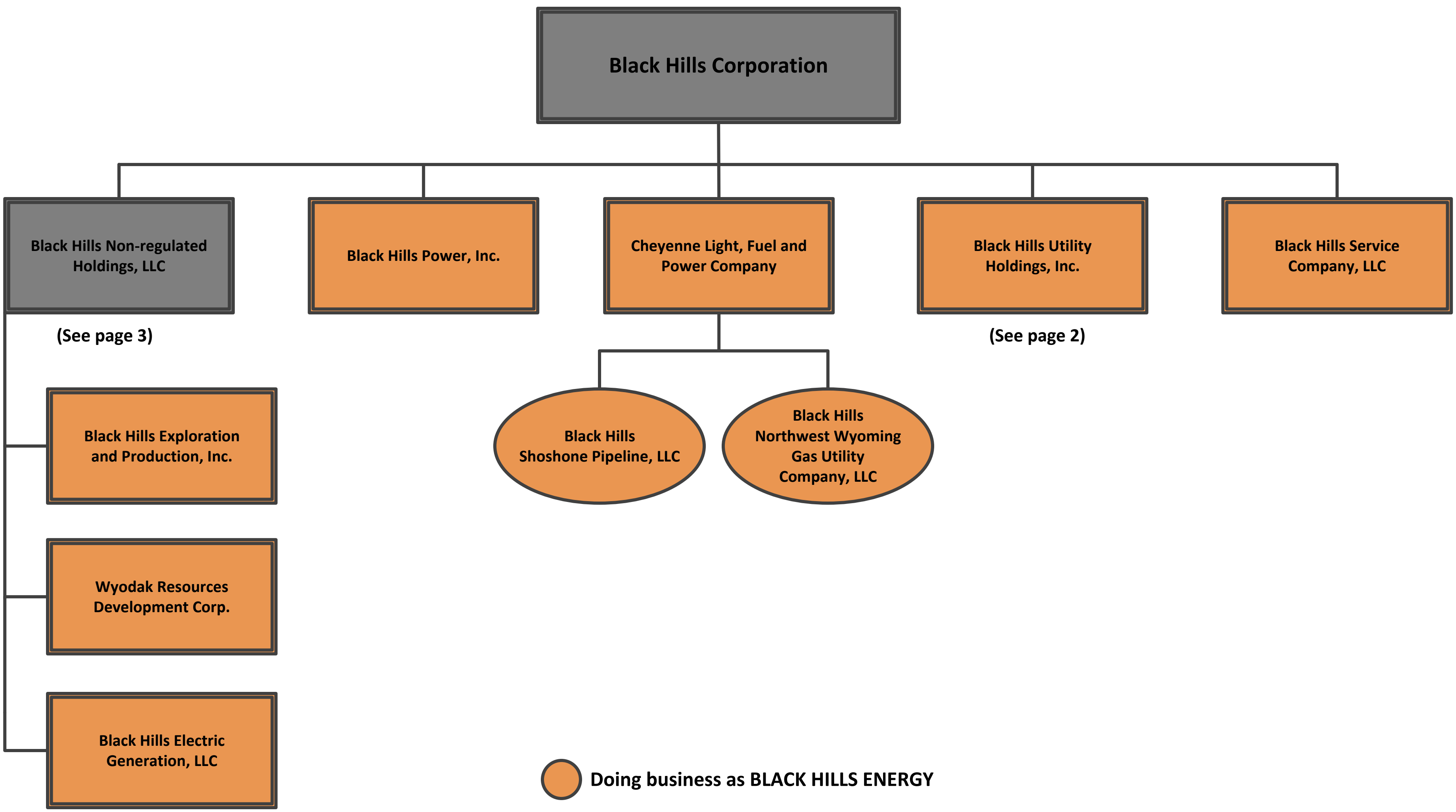
Transmission Ratio – Based on a simple average of a multiple of cross-sectional drivers for the transmission function as of September 30th for the prior year that includes customer counts, peak load, number of substations, number of feeders, number of distribution and transmission miles, and number of remote terminal units. The numerator of which is for an applicable operating company and the denominator of which is for all applicable operating companies.

The departments that utilize this ratio include Transmission Planning, T&D Engineering, NERC Compliance, FERC Tariff and Compliance, Transmission and Distribution Reliability, NERC Transmission and Tech Support, Transmission Service Management, Substation/Protection Eng, Engineering Resources, Elec Maint Services, and Vegetation Management.

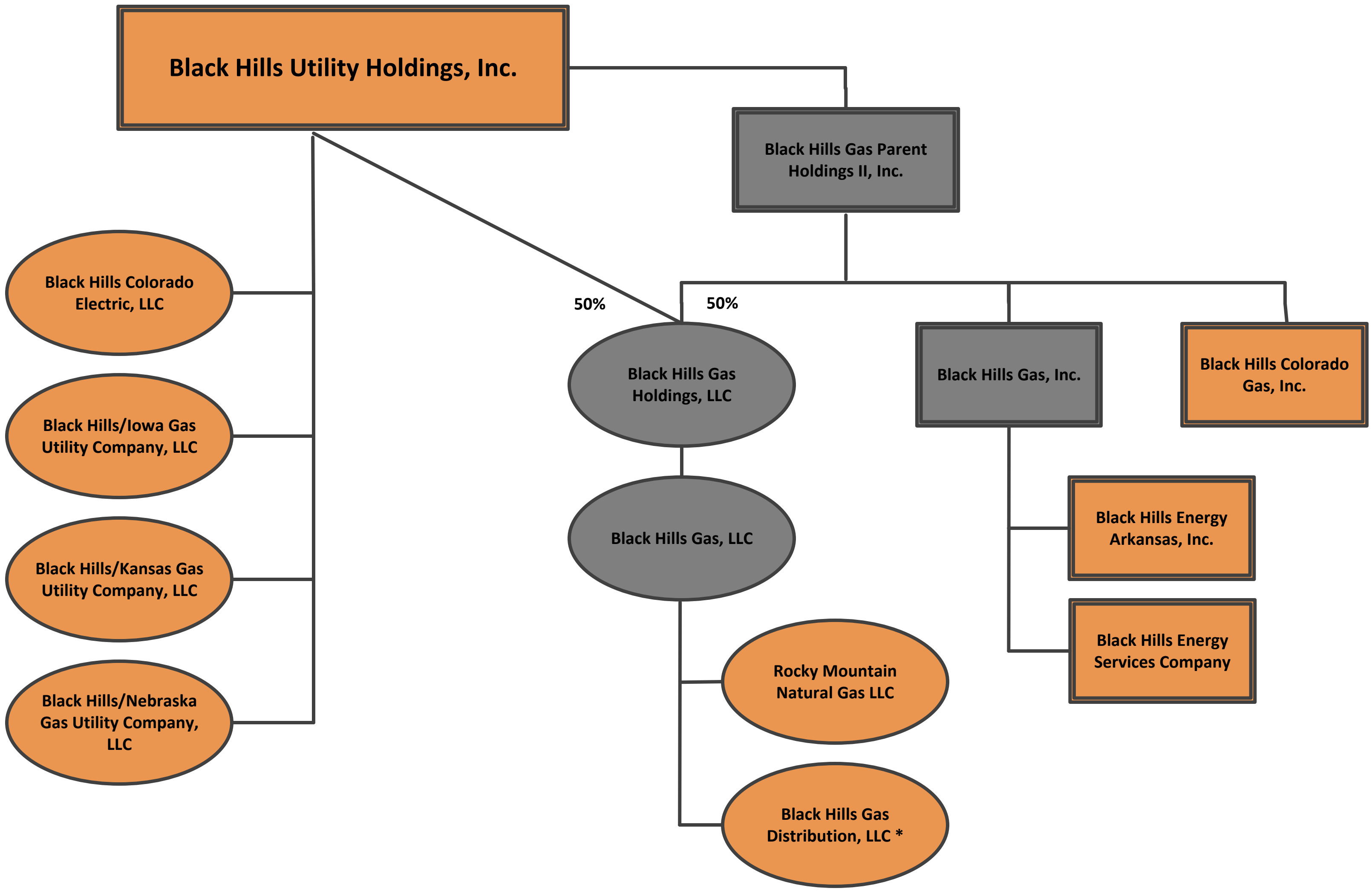
Document Content(s)

Date: 12-31-18

BLACK HILLS CORPORATION
LEGAL ORGANIZATIONAL CHART



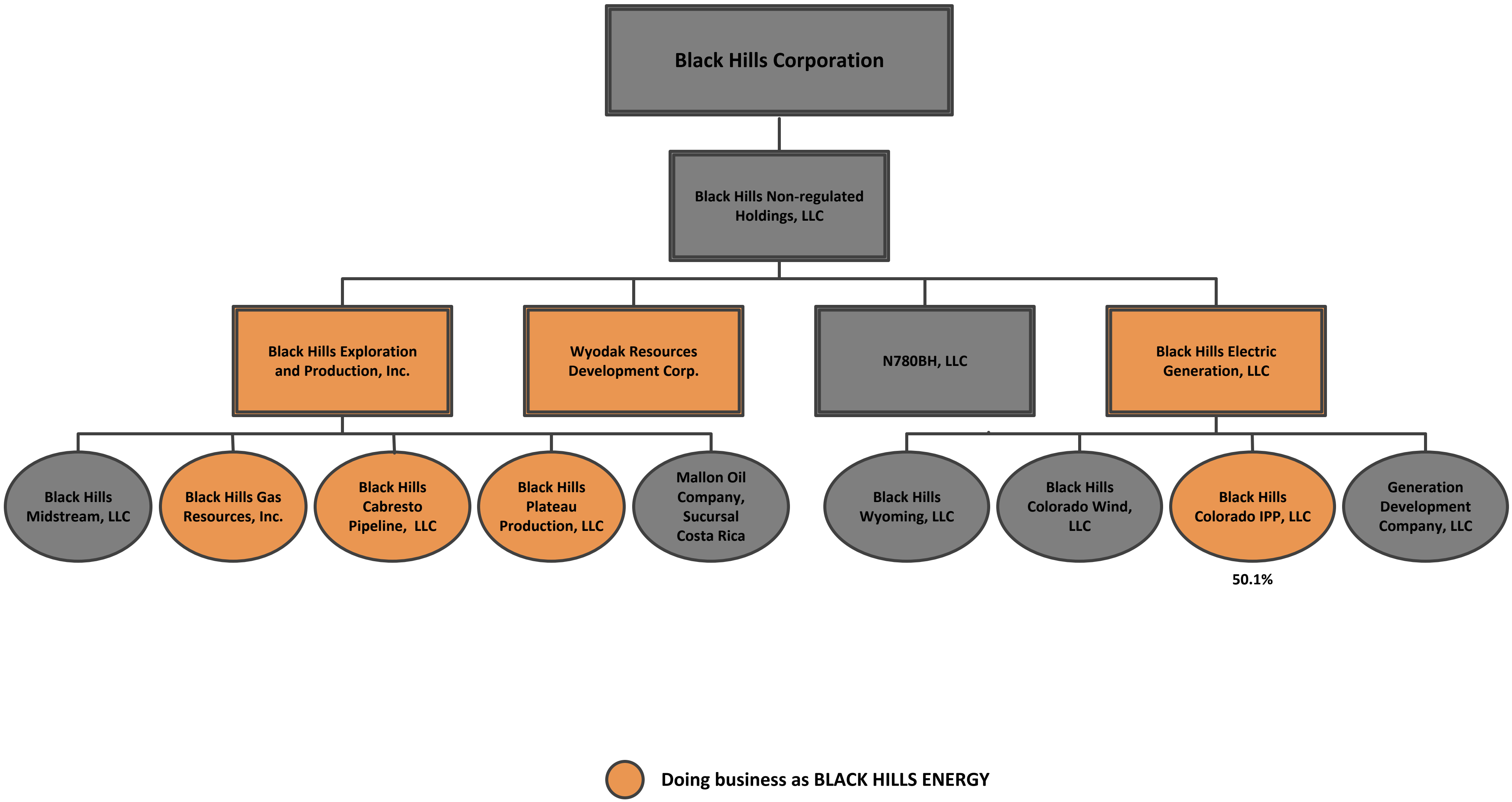
BLACK HILLS CORPORATION
LEGAL ORGANIZATIONAL CHART



Doing business as BLACK HILLS ENERGY

* Represents state gas divisions in NE and WY

BLACK HILLS CORPORATION
LEGAL ORGANIZATIONAL CHART



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________ to _________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	7001 Mount Rushmore Road	IRS Identification Number
	Rapid City, South Dakota 57702	46-0458824

Registrant's telephone number, including area code
(605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2018 $3,239,030,444

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2019
Common stock, $1.00 par value	60,003,965 shares

Documents Incorporated by Reference
Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2019 Annual Meeting of Stockholders to be held on April 30, 2019, are incorporated by reference in Part III of this Form 10-K.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the "Company," "we," "us" or "our"), is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, with the purchase of the Wyodak coal mine, we began producing and selling energy through non-regulated businesses.

We operate our business in the United States, reporting our operating results through our regulated Electric Utilities, regulated Gas Utilities, Power Generation and Mining segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 212,000 electric customers in Colorado, Montana, South Dakota and Wyoming. Our Electric Utilities own 939 MW of generation and 8,858 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,054,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate approximately 4,700 miles of intrastate gas transmission pipelines and 41,158 miles of gas distribution mains and service lines, seven natural gas storage sites, over 45,000 horsepower of compression and nearly 600 miles of gathering lines.

Our Power Generation segment produces electric power from its wind, natural gas and coal generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Mining segment produces coal at our mine near Gillette, Wyoming, and sells the coal primarily under long-term contracts to mine-mouth electric generation facilities owned by our Electric Utilities and Power Generation businesses.

Electric Utilities Segment

We conduct electric utility operations through our South Dakota, Wyoming and Colorado subsidiaries. Our Electric Utilities generate, transmit and distribute electricity to approximately 212,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services through our Tech Services product lines.

Capacity and Demand. System peak demands for the Electric Utilities for each of the last three years are listed below:

	System Peak Demand (in MW)					
	2018		2017		2016	
	Summer	Winter	Summer	Winter	Summer	Winter
South Dakota Electric	437	379	447	402	438	389
Wyoming Electric [(a)]	254	238	249	230	236	230
Colorado Electric [(b)]	413	313	398	299	412	302
Total Electric Utilities' Peak Demands	1,104	930	1,094	931	1,086	921

(a) The July 2018 summer peak load of 254 surpassed previous summer peak record load of 249 set in July 2017. The December 2018 winter peak load of 238 surpassed the previous winter peak record load of 230 set in December 2016.

(b) The July 2018 summer peak load of 413 surpassed previous summer peak record load of 412 set in July 2016. The October 2018 winter peak load of 313 surpassed previous winter peak load of 310 set in February 2011.

FORM 10K

Federal Regulation

Energy Policy Act. Black Hills Corporation is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and holding companies regulated by FERC under the Federal Power Act and PUHCA 2005.

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, and terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public Electric Utilities' subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities, Black Hills Colorado IPP and Black Hills Wyoming are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. Our Electric Utilities own and operate FERC-jurisdictional interstate transmission facilities and provide open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

The Federal Power Act authorizes FERC to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of a utility holding company. As a utility holding company with a centralized service company subsidiary, BHSC, we are subject to FERC's authority under PUHCA 2005.

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2018, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of approximately 283 MW.

We produce electric power from our generating plants and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell a substantial majority of our non-regulated generating capacity under contracts having terms greater than one year.

As of December 31, 2018, the power plant ownership interests held by our Power Generation segment include:

Power Plants	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	In Service Date
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation [(a)]	Gas	Pueblo, Colorado	50.1%	200.0	2012
Busch Ranch I	Wind	Pueblo, Colorado	50.0%	14.5	2012
				283.4	

(a) Black Hills Colorado IPP owns and operates this facility. This facility provides capacity and energy to Colorado Electric under a 20-year PPA with Colorado Electric. This PPA is accounted for as a capital lease on the accompanying Consolidated Financial Statements.

Black Hills Wyoming - Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant and MEAN owns the remaining 23.5%. We sell 60 MW of unit-contingent capacity and energy from this plant to Wyoming Electric under a PPA that expires on December 31, 2022. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical to do so. The PPA includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. See the purchased power discussion within the Electric Utilities segment above about Wyoming Electric's 2018 integrated resource plan which included a recommendation to the WPSC to acquire Wygen I.

Black Hills Colorado IPP - Pueblo Airport Generation. The Pueblo Airport Generating Station consists of two 100 MW combined-cycle gas-fired power generation plants located at a site shared with Colorado Electric. The plants commenced operation on January 1, 2012 and the assets are accounted for as a capital lease under a 20-year PPA with Colorado Electric, which expires on December 31, 2031. Under the PPA with Colorado Electric, any excess capacity and energy shall be for the benefit of Colorado Electric.

Black Hills Electric Generation (BHEG) - Busch Ranch I. On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest in the 29 MW Busch Ranch I Wind Farm, previously owned by AltaGas. Black Hills Electric Generation will provide its share of energy from the wind farm to Colorado Electric through a new PPA which has the same terms as the PPA it replaces that Colorado Electric had with AltaGas, expiring in October 2037.

Third Party Noncontrolling Interest in Subsidiary

In 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third party buyer. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes. The operating results for Black Hills Colorado IPP remain consolidated with Black Hills Electric Generation, as Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest.

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) [a]	2018	2017	2016
Sold			
Black Hills Colorado IPP [b]	1,000,577	943,618	1,223,949
Black Hills Wyoming [c]	582,938	645,810	644,564
Black Hills Electric Generation	5,873	—	—
Total Sold	1,589,388	1,589,428	1,868,513
Generated			
Black Hills Colorado IPP [b]	1,000,577	943,618	1,223,949
Black Hills Wyoming [c]	501,945	577,124	543,546
Black Hills Electric Generation	5,873	—	—
Total Generated	1,508,395	1,520,742	1,767,495
Purchased			
Black Hills Wyoming	83,213	69,377	85,993
Total Purchased	83,213	69,377	85,993

(a) Company use and losses are not included in the quantities sold, generated and purchased.
(b) The decrease in 2017 was driven by the joint dispatch agreement Colorado Electric joined in 2017. See details of this agreement above in the Electric Utilities segment.
(c) The decrease in 2018 was driven by a planned outage at Wygen I.

Operating Agreements. Our Power Generation segment has the following material operating agreements:

- Economy Energy PPA and other ancillary agreements
    - Black Hills Wyoming has ancillary agreements with the City of Gillette, Wyoming to operate CTII, and provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreements include a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.
- Operating and Maintenance Services Agreement
    - In conjunction with the sale of the noncontrolling interest on April 14, 2016, an operating and maintenance services agreement was entered into between Black Hills Electric Generation and Black Hills Colorado IPP. This agreement sets forth the obligations and responsibilities of Black Hills Electric Generation as the operator of the generating facility owned by Black Hills Colorado IPP. This agreement is in effect from the date of the noncontrolling interest purchase and remains effective as long as the operator or one of its affiliates is responsible for managing the generating facilities in accordance with the noncontrolling interest agreement, or until termination by owner or operator.
- Shared Services Agreements
    - South Dakota Electric, Wyoming Electric and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.
    - Black Hills Colorado IPP and Colorado Electric are parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric's assets.
    - Black Hills Colorado IPP, Wyoming Electric and South Dakota Electric are parties to a Spare Turbine Use Agreement, whereby Black Hills Colorado IPP charges South Dakota Electric and Wyoming Electric a monthly fee for the availability of a spare turbine to support the operation of Cheyenne Prairie Generating Station.
    - Black Hills Colorado IPP and Black Hills Wyoming receive certain staffing and management services from BHSC.
- Jointly Owned Facilities
    - Black Hills Wyoming and MEAN are parties to a shared joint ownership agreement, whereby Black Hills Wyoming charges MEAN for administrative services, plant operations and maintenance on its share of the Wygen I generating facility over the life of the plant.
    - Black Hills Electric Generation and Colorado Electric both own 50% of the Busch Ranch I Wind Farm. Black Hills Electric Generation purchased its 50% share in Busch Ranch I from AltaGas on December 11, 2018. See details of the PPA and ownership agreement discussed previously in the Electric Utilities segment.

Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for independent power producers in some regions.

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own three EWGs: Wygen I, 200 MW (two 100 MW combined-cycle gas-fired units) at the

Pueblo Airport Generating Station, and Black Hills Electric Generation's interest in Busch Ranch I. Our EWGs were granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates.

Mining Segment

Our Mining segment operates through our WRDC subsidiary. We surface mine, process and sell primarily low-sulfur sub-bituminous coal at our mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 4.1 million tons of coal in 2018.

During our surface mining operations, we strip and store the topsoil. We then remove the overburden (earth and rock covering the coal) with heavy equipment. Removal of the overburden typically requires drilling and blasting. Once the coal is exposed, we drill, fracture and systematically remove it, using front-end loaders and conveyors to transport the coal to the mine-mouth generating facilities. We reclaim disturbed areas as part of our normal mining activities by back-filling the pit with overburden removed during the mining process. Once we have replaced the overburden and topsoil, we reestablish vegetation and plant life in accordance with our approved post-mining topography plan.

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has in recent years trended upwards. The overburden ratio at December 31, 2018 was 2.20 which increased from the prior year as we continued mining in areas with higher overburden. We expect our stripping ratio to be approximately 2.26 by the end of 2019 as we mine in areas with comparable overburden.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between April 30, 2019 and September 30, 2025 and the state lease expires on August 1, 2023. The duration of the leases varies; however, the lease terms generally are extended to the exhaustion of economically recoverable reserves, as long as active mining continues. We pay federal and state royalties of 12.5% of the selling price of all coal. As of December 31, 2018, we estimated our recoverable coal reserves to be approximately 189 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering studies. The recoverable coal reserve life is equal to approximately 46 years at the current production levels. Our recoverable coal reserve estimates are periodically updated to reflect past coal production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable coal reserves include reserves that can be economically and legally extracted at the time of their determination. We use various assumptions in preparing our estimate of recoverable coal reserves. See Risk Factors under Mining for further details.

Substantially all of our coal production is currently sold under contracts to:

- South Dakota Electric for use at the 90 MW Neil Simpson II plant to which we sell approximately 500,000 tons of coal each year. This contract is for the life of the plant;

- Wyoming Electric for use at the 95 MW Wygen II plant to which we sell approximately 550,000 tons of coal each year. This contract is for the life of the plant;

- The 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by South Dakota Electric. PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustments for planned outages. South Dakota Electric is also obligated to purchase a minimum of 0.375 million tons of coal per year for its 20% share of the power plant, subject to adjustments for planned outages. This contract expires December 31, 2022;

- The 110 MW Wygen III power plant owned 52% by South Dakota Electric, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons of coal each year. This contract expires June 1, 2060;

- The 90 MW Wygen I power plant owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons of coal each year. This contract expires June 30, 2038; and

- Certain regional industrial customers served by truck to which we sell a total of approximately 150,000 tons of coal each year. These contracts have terms of one to five years.

Our Mining segment sells coal to South Dakota Electric and Wyoming Electric for all of their requirements under cost-based agreements that regulate earnings from these affiliate coal sales to a specified return on our coal mine's cost-depreciated investment base. The return calculated annually is 400 basis points above A-rated utility bonds applied to our Mining investment base. South Dakota Electric made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for South Dakota Electric's operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant and through June 1, 2060, for Wygen III. The agreement with Wyoming Electric provides coal for the life of the Wygen II plant.

The price of unprocessed coal sold to PacifiCorp for the Wyodak plant is determined by the coal supply agreement described above. The agreement includes a price adjustment in 2019. The price adjustment essentially allows us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustment is based on the market price of coal plus considerations for the avoided costs of rail transportation and a coal unloading facility, which PacifiCorp would have to incur if it purchased coal from another mine. In addition, the agreement also provides for the monthly escalation of coal price based on an escalation factor.

The current contract price ($19.08 per ton as of December 2018) is comprised of three components: 1) avoided transportation costs (approximately 20% of current price); 2) avoided costs of a coal unloading facility (approximately 30% of current price); and 3) a rolling 12-month average of the Coal Daily spot market price of 8,400 Btu Powder River Basin coal (approximately 50% of current price). With respect to the 2019 coal price re-opener, we expect the transportation and unloading costs to escalate slightly. The current trailing 12-month spot price of 8,400 Btu Powder River Basin coal, ending March 2019, is approximately one dollar less than the price used for the 2014 price re-opener.

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement using a base price that includes price escalators and quality adjustments through June 30, 2038 and includes actual cost per ton plus a margin equal to the yield for Moody's A-Rated 10-Year Corporate Bond Index plus 400 basis points with the base price being adjusted on a 5-year interval. The agreement stipulates that WRDC will supply coal to the 90 MW Wygen I plant through June 30, 2038.

Competition. Our primary strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically, off-site sales have been to consumers within a close proximity to the mine. Rail transport market opportunities for WRDC coal are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC coal mine is served by only one railroad, resulting in less competitive transportation rates. Management continues to explore the limited market opportunities for our product through truck transport.

Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental considerations and availability affect the overall demand for coal as a fuel.

Environmental Matters. We are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. See Environmental Matters section for further information.

Mine Reclamation. Reclamation is required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five-year mining permit issued by the State of Wyoming. In 2016, that five-year permit was re-issued. Based on extensive reclamation studies, we have accrued approximately $16 million for reclamation costs as of December 31, 2018. Mining regulatory requirements continue to increase, which impose additional cost on the mining process.

Environmental Matters

South Dakota and Wyoming Power Generation. Based on current regulations, technology and plans, the following table contains our current estimates of capital expenditures expected to be incurred over the next three years to comply with current environmental laws and regulations as described below, including regulations that cover water, air, soil and other pollutants, but excluding plant closures and the cost of new generation. The ultimate cost could be significantly different from the amounts estimated.

Environmental Expenditure Estimates	Total (in thousands)
2019	$ 1,503
2020	1,088
2021	710
Total	$ 3,301

Methane Rules (Greenhouse Gas Emissions). The EPA and the State of Colorado have implemented strict regulatory requirements on hydrocarbon and methane emissions associated with natural gas gathering and transmission systems. The BLM repealed similar hydrocarbon and methane emissions reductions it previously established under the Methane Rule (Venting and Flaring rule). Presently, we have four facilities in our Colorado natural gas transmission operations affected by the hydrocarbon and methane reduction rules.

Our operations are currently in compliance with both EPA and State of Colorado rules. Future modifications to our gathering and transmissions systems are anticipated to trigger EPA methane rules. We plan to develop a corporate-wide methane control strategy to address GHG emissions from our natural gas operations as we anticipate this will be a requirement in future rule-making efforts.

Water Issues. Our facilities are subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the Clean Water Act and govern overall water/wastewater discharges through EPA's surface water discharge and storm water permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. The EPA proposed effluent limitation guidelines and standards on June 7, 2013 and published the final rule on November 3, 2015. In 2017, the EPA postponed the implementation of the rule and set a timeline in 2018 to revise the rule. To date, the rule has not been sent for publication. This rule will have an impact on the Wyodak Plant. Until the EPA issues the rule for publication, we can not quantify what the potential impact may be on the Wyodak Plant. The terms of this new regulation may impact the next permit renewal, which will be in 2020.

Short-term Emission Limits. The EPA and State Air Quality Programs implemented short-term emission limits for coal and natural gas-fired generating units during normal and start-up operating scenarios for SO_2, NO_x and Opacity. The limits pertain to emissions during start-up periods and upset conditions such as mechanical malfunctions. State and federal regulatory agencies typically excuse short-term emissions exceedances if they are reported and corrected immediately or if it occurs during start-up.

We proactively manage this requirement through maintenance efforts and installing additional pollution control systems to control SO_2 emission short-term excursions during start-up. These actions have nearly eliminated our short-term emission limit compliance risk while plant availability remained above 90% for all four of our coal-fired plants. To eliminate the remaining potential for exceedances, an innovative trip logic mechanism was implemented to shut the power plant down if a predicted emission limit is to be exceeded. Similar efforts have been taken and similar results achieved with our natural gas fired combustion turbine sites as well.

Regional Haze (Impacts to the Wyodak Power Plant). The EPA Regional Haze rule was promulgated to improve visibility in our National Parks and Wilderness Areas. The State of Wyoming proposed controls in its Regional Haze State Implementation Plan (SIP) which allowed PacifiCorp to install low-NO_x burners in the Wyodak Plant, of which South Dakota Electric owns 20%. The EPA did not agree with the State of Wyoming's determination and overruled it in a Federal Implementation Plan (FIP). The State of Wyoming and other interested parties are challenging the EPA's determination. If the challenge is unsuccessful, additional capital investment would be necessary to bring the Wyodak Plant into compliance. Our 20% share of this capital investment for the facility would be approximately $40 million if PacifiCorp is required to install a Selective Catalytic Reactor for NO_x control. The case is currently held in abeyance at the 10th circuit court while a settlement reached between one of the interested parties and the EPA is implemented.

Mining. Operations at the WRDC mine must regularly address issues related to the proximity of the mine disturbance boundary to the City of Gillette, and to residential and industrial properties. Homeowner complaints and challenges to the permits may occur as mining operations move closer to residential areas. Specific concerns could include damage to wells, fugitive dust emissions, vibration and an emissions cloud from blasting.

Former Manufactured Gas Plants (FMGP). Federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. Our Gas Utilities are managing FMGP sites in Iowa and Nebraska. We are currently in discussions with EPA, state regulators, and/or other third-parties to determine the ultimate resolution to these sites. As of December 31, 2018, we are working on the site in Council Bluffs, Iowa, and the site in McCook, Nebraska. We have been contacted by a third-party who indicated it intends to manage and pay for the clean-up at the McCook Nebraska site.

Affordable Clean Energy Rule. The EPA was directed to repeal, revise, and replace the Clean Power Plan rule. On August 31, 2018, the EPA published the proposed Affordable Clean Energy rule. This rule focuses on heat-rate improvements on coal-fired boiler units and poses significantly less risk than the Clean Power Plan. The 60-day comment period has ended and the EPA is reviewing comments prior to issuing a final rule.

OSM Coal Combustion Residual Rule (CCR). The EPA issued the CCR which is currently effective and establishes requirements to protect surface and groundwater from impacts of coal ash impoundments. WRDC is exempt from the EPA CCR because coal ash is used for backfill reclamation in the areas previously mined. The current administration has not pursued further modification of the CCR.

Environmental risk changes constantly with the implementation of new or modified regulations, changing stakeholder interests and needs, and through the introduction of innovative work practices and technologies. We assess risk annually and develop mitigation strategies to successfully and responsibly manage and ensure compliance across the enterprise. For additional information on environmental matters, see Item 1A and Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Other Properties

In addition to the facilities previously disclosed in Items 1 and 2, we own or lease several facilities throughout our service territories. Our owned facilities are as follows:

- In Rapid City, South Dakota, we have a 220,000 square foot corporate headquarters building, Horizon Point, which was completed in the fourth quarter of 2017.

- In Arkansas, Nebraska, Iowa, Colorado, Kansas and Wyoming we own various office, service center, storage, shop and warehouse space totaling over 805,000 square feet utilized by our Gas Utilities.

- In South Dakota, Wyoming, Colorado and Montana we own various office, service center, storage, shop and warehouse space totaling approximately 240,000 square feet utilized by our Electric Utilities and Mining segments.

In addition to our owned properties, we lease 194,361 square feet of properties within our service areas.

Substantially all of the tangible utility properties of South Dakota Electric and Wyoming Electric are subject to liens securing first mortgage bonds issued by South Dakota Electric and Wyoming Electric, respectively.

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BOARD OF DIRECTORS

David R. Emery, age 56, was elected to the Board in 2004. He has been Executive Chairman since January 1, 2019, was our Chairman and CEO from 2016 through 2018, and Chairman, President and CEO from 2005 through 2015. Prior to that he held various positions with the Company, including President and Chief Executive Officer from 2004 to 2005, President and COO — Retail Business Segment from 2003 to 2004, and Vice President—Fuel Resources from 1997 to 2003.

Linden R. Evans, age 56, was elected to the Board in November 2018. He has been President and Chief Executive Officer since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer — Utilities from 2004 through 2015. Prior to that he served as the Vice President and General Manager of our former telecommunications subsidiary in 2003 and 2004, and Associate Counsel from 2001 to 2003.

Michael H. Madison, age 70, was elected to the Board in 2012 and chairs the Compensation Committee. He was President, CEO and a Director of Cleco Corp., a public utility holding company, from 2005 to 2011, President and COO of Cleco Power, LLC from 2003 to 2005, and State President, Louisiana-Arkansas with American Electric Power from 2000 to 2003.

Steven R. Mills, age 63, was elected to the Board in 2011 and chairs the Audit Committee. He has been a Financial Consultant and Advisor in the private equity, agribusiness, renewable products and financial services fields since 2013. He previously served as CFO of Amyris, Inc., an integrated renewable products company, from 2012 to 2013. Prior to that, he held several executive positions, including Senior Executive Vice President Performance and Growth and CFO at Archer Daniels Midland Co., a processor, transporter, buyer and marketer of agricultural products. He also serves on the Board of Amyris, Inc.

Robert P. Otto, age 59, was elected to the Board in 2017. He has been the owner of Bob Otto Consulting LLC, providing strategic planning and services in cyber security, intelligence and reconnaissance since 2017. He retired from the U.S. Air Force in 2016 as a lieutenant general. He served as a general officer since 2008, culminating as the Deputy Chief of Staff for Intelligence, Surveillance and Reconnaissance.

Rebecca B. Roberts, age 66, was elected to the Board in 2011 and chairs the Governance Committee. She was President of Chevron Pipe Line Co., a transporter of crude oil, refined petroleum products, liquefied petroleum gas, natural gas and chemicals within the U.S. from 2006 to 2011, and President of Chevron Global Power Generation from 2003 to 2006. She also serves on the Board of AbbVie, Inc. and MSA Safety, Inc.

Mark A. Schober, age 63, was elected to the Board in 2015. He was Senior Vice President and CFO of ALLETE, Inc., a public energy company, from 2006 to 2014. He previously held several positions in accounting and finance.

Teresa A. Taylor, age 55, was elected to the Board in 2016. She has been CEO of Blue Valley Advisors, LLC since 2011. She previously served as COO of Qwest Communications, Inc., a telecommunications carrier, from 2009 to 2011. She also served in other leadership roles at Qwest and the former U.S. West beginning in 1987, including Executive Vice President and Chief Administrative Officer. She also serves on the Board of T-Mobile USA, Inc. and First Interstate BancSystem, Inc.

John B. Vering, age 69, was elected to the Board in 2005 and serves as our Lead Director. He has been Managing Director of Lone Mountain Investments, Inc., an oil and gas investment firm, since 2002. He previously held several executive positions in the oil and gas industry.

Thomas J. Zeller, age 71, was elected to the Board in 1997. He was CEO of RESPEC, a technical consulting and services firm with expertise in engineering, information technologies and water and natural resources, specializing in emerging environmental protection protocols, in 2011, and served as President from 1995 to 2011.

CORPORATE GOVERNANCE

Corporate Governance Guidelines

Our Board of Directors has adopted corporate governance guidelines titled "Corporate Governance Guidelines of the Board of Directors," which guide the operation of our Board and assist the Board in fulfilling its obligations to shareholders and other constituencies. The guidelines lay the foundation for the Board's responsibilities, operations, leadership, organization and committee matters. The Governance Committee reviews the guidelines annually, and the guidelines may be amended at any time, upon recommendation by the Governance Committee and approval of the Board. These guidelines can be found in the "Governance" section of our website (www.blackhillscorp.com/investor-relations/corporate-governance).

Board Independence

In accordance with NYSE rules, the Board of Directors through its Governance Committee affirmatively determines the independence of each director and director nominee in accordance with guidelines it has adopted, which include all elements of independence set forth in the NYSE listing standards. These guidelines are contained in our Policy for Director Independence, which can be found in the "Governance" section of our website (www.blackhillscorp.com/investor-relations/corporate-governance). Based on these standards, the Governance Committee determined that each of the following non-employee directors is independent and has no relationship with us, except as a director and shareholder:

Michael H. Madison Steven R. Mills Robert P. Otto Rebecca B. Roberts	80% INDEPENDENT	Mark A. Schober Teresa A. Taylor John B. Vering Thomas J. Zeller

In addition, based on such standards, the Governance Committee determined that Messers. Emery and Evans are not independent because they are Officers of the Company.

Board Leadership Structure

As part of a planned leadership transition, Mr. Emery, after 14 years as Chairman and CEO, was appointed Executive Chairman of the Board of Directors. Mr. Evans, who has been President and Chief Operating Officer since 2016, was named President and CEO effective January 1, 2019. To ensure a seamless transition of our CEO role, Mr. Emery collaborates closely with our new CEO on corporate strategy and other items.

Our Board has and continues to value a high degree of Board independence. As a result, our corporate governance structure and practices promote a strong, independent Board and include several independent oversight mechanisms. Only independent directors serve on our Audit, Compensation and Governance Committees. Our Board believes these practices ensure that experienced and independent directors will continue to effectively oversee management and critical issues related to financial and operating plans, long-range strategic issues, enterprise risk and corporate integrity. All of our Board committees may seek legal, financial or other expert advice from a source independent of management.

As provided in our Corporate Governance Guidelines of the Board of Directors, because our Executive Chairman is not independent, our Board annually appoints an independent Lead Director. John B. Vering is our current Lead Director and has served in this role since March 2016. As provided in the Corporate Governance Guidelines, the primary responsibilities of the Lead Director are to chair executive sessions of the independent directors, and in conjunction with the Executive Chairman, communicate the Board's annual evaluation of the CEO. The Lead Director, together with the independent directors, establishes the agenda for executive sessions, which are held at each regular Board meeting. The Lead Director serves as a liaison between the independent members of the Board, the Executive Chairman, and the CEO, as appropriate, and discusses, to the extent appropriate, matters raised by the independent directors in executive session. The Lead Director also consults with the Executive Chairman, and the CEO, as appropriate, regarding meeting agendas and presides over regular meetings of the Board in the absence of the Executive Chairman. This leadership structure provides consistent and effective oversight of our management and our Company.

Risk Oversight

Our Board oversees an enterprise approach to risk management that supports our operational and strategic objectives. The Corporate Governance Guidelines of the Board of Directors provide that the Board will review major risks facing our Company and the options for risk mitigation presented by management. Our Board delegates oversight of certain risk considerations to its committees within each of their respective areas of responsibility; however, the full Board monitors risk relating to strategic planning and execution, as well as executive succession. Financial risk oversight falls within the purview of our Audit Committee. Our Compensation Committee oversees compensation and benefit plan risks. Each committee reports to the full Board.

Our Board reviews any material changes in our key enterprise risk management ("ERM") issues, including cyber security, with management at each quarterly Board meeting. In addition, the Board reviews a deep dive enterprise risk topic with our Chief Risk Officer at most quarterly meetings. In so doing, our Board seeks to ensure appropriate risk mitigation strategies are implemented by management on an ongoing basis. Operational and strategic plan presentations by management to our Board include consideration of the challenges and risks to our business. Our Board and management actively engage in discussions of these topics and utilize outside consultants as needed. Our Board oversees the assessment of our strategic plan risks as part of our strategic planning process. In addition, our Board periodically receives safety performance, operations, environmental, legal and compliance reports.

Our Audit Committee oversees management's strategy and performance relative to our significant financial risks. In consultation with management, the independent auditors and the internal auditors, the Audit Committee discusses our risk assessment, risk management and credit policies and reviews significant financial risk exposures, along with steps management has taken to monitor, mitigate and report such exposures. At least twice a year, our Chief Risk Officer provides a Risk Report and the Treasurer provides a Credit Report to the Audit Committee. We adopted a Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within established risk tolerances.

Our Compensation Committee adopted an executive compensation philosophy that provides the foundation for our executive compensation program. The executive compensation philosophy states that the executive pay program should be market-based and maintain an appropriate and competitive balance between fixed and variable pay elements, short-term and long-term compensation and cash and stock-based compensation. The Compensation Committee establishes company-specific performance goals with potential incentive payouts for our executive officers to motivate and reward performance, consistent with our long-term success. The target compensation for our senior officers is weighted in favor of long-term incentives, aligning performance incentives with long-term results for our shareholders. Our Compensation Committee also sets minimum performance thresholds and maximum payouts in the incentive programs and maintains the discretion to reduce awards if excessive risk is taken. Stock ownership guidelines established for all of our officers require our executives to hold 100 percent of all shares awarded to them (net of share withholding for taxes and, in the case of cashless stock option exercises, net of the exercise price and withholding for taxes) until the established stock ownership guidelines are achieved. Our Compensation Committee also includes "clawback" provisions in our incentive plans, which may require an executive to return incentives received, if the Compensation Committee determines, in its discretion, that the executive engaged in specified misconduct or wrongdoing or in the event of certain financial restatements.

In addition, management periodically conducts and our Compensation Committee reviews a risk assessment of the Company's compensation policies and practices for all employees. This was last done in December 2017 and there have been no material changes in our policies and practices since that time. Key members of human resources, legal, risk, finance, audit and operations departments were included in the review to ensure accuracy and completeness of the scope and findings. The assessment demonstrated that our compensation programs are designed to minimize financial and reputational risks and do not create risks that are reasonably likely to have a material adverse effect on the Company.

Our management is responsible for day-to-day risk management and operates under an ERM program that addresses strategic, operational, financial and compliance risks. The ERM program includes practices to identify risks, assesses the impact and probability of occurrence, and develops action plans to prevent the occurrence or mitigate the impact of the risk. The ERM program includes regular reporting to our senior management team and includes monitoring and testing by the Chief Risk Officer and Risk Management, Compliance and Internal Audit groups. The Chief Risk Officer reviews the overall ERM program with the Board of Directors on a regular basis.

We believe the division of risk management responsibilities described above is an effective approach for addressing the risks facing our Company.

Director Nominees

The Governance Committee uses a variety of methods for identifying and evaluating nominees for director. The Governance Committee regularly assesses the appropriate size of the Board and whether any vacancies on the Board are expected due to retirement or otherwise. In the event vacancies are anticipated, or otherwise arise, the Governance Committee considers various potential candidates for director. Board candidates are considered based upon various criteria, including diverse business, administrative and professional skills or experiences; an understanding of relevant industries, technologies and markets; financial literacy; independence status; the ability and willingness to contribute time and special competence to Board activities; personal integrity and independent judgment; and a commitment to enhancing shareholder value. The Governance Committee considers these and other factors as it deems appropriate, given the needs of the Board. Our goal is a balanced and diverse Board, with members whose skills, background and experience are complementary and, together, cover the spectrum of areas that impact our business currently and in the future. The Governance Committee considers candidates for Board membership suggested by a variety of sources, including current or past Board members, the use of third-party executive search firms, members of management and shareholders. Any shareholder may make recommendations for consideration by the Governance Committee for membership on the Board by sending a written statement of the qualifications of the recommended individual to the Corporate Secretary. There are no differences in the manner by which the Committee evaluates director candidates recommended by shareholders from those recommended by other sources.

Shareholders who intend to nominate persons for election to the Board of Directors must provide timely written notice of the nomination in accordance with Article I, Section 9 of our Bylaws. Generally, our Corporate Secretary must receive the written notice at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders. For the 2020 shareholder meeting, those dates are January 31, 2020 and January 1, 2020. The notice must set forth at a minimum the information set forth in Article I, Section 9 of our Bylaws, including the shareholder's identity and status, contingent ownership interests, description of any agreement made with others acting in concert with respect to the nomination, specific information about the nominee and certain representations by the nominee to us.

Communications with the Board

Shareholders and others interested in communicating directly with the Lead Director, with the independent directors as a group, or the Board of Directors may do so in writing to the Lead Director, Black Hills Corporation, 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709.

Corporate Governance Documents

The charters of the Audit, Compensation and Governance Committees, as well as the Corporate Governance Guidelines of the Board of Directors, Policy for Director Independence, Code of Business Conduct and the Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and certain other persons performing similar functions can be found in the "Governance" section of our website (www.blackhillscorp.com/investor-relations/corporate-governance). We intend to disclose any amendments to, or waivers of, the Code of Ethics on our website. Please note that none of the information contained on our website is incorporated by reference in this proxy statement.

The Corporate Governance Guidelines include a plurality plus voting policy. Pursuant to the policy, any nominee for election as a director in an uncontested election who receives a greater number of votes "Withheld" from his or her election than votes "For" his or her election will promptly tender his or her resignation as a director to the Chairman of the Board following certification of the election results. Broker non-votes will not be deemed to be votes "For" or "Withheld" from a director's election for purposes of the policy. The Governance Committee (without the participation of the affected director) will consider each resignation tendered under the policy and recommend to the Board whether to accept or reject it. The Board will then take the appropriate action on each tendered resignation, taking into account the Governance Committee's recommendation. The Governance Committee in making its recommendation, and the Board in making its decision, may consider any factors or other information that it considers appropriate, including the reasons why the Governance Committee believes shareholders "Withheld" votes for election from such director and any other circumstances surrounding the "Withheld" votes, any alternatives for curing the underlying cause of the "Withheld" votes, the qualifications of the tendering director, his or her past and expected future contributions to us and the Board, and the overall composition of the Board, including whether accepting the resignation would cause us to fail to meet any applicable SEC or NYSE requirements. The Board will publicly disclose by filing with the SEC on Form 8-K its decision and, if applicable, its rationale within 90 days after receipt of the tendered resignation.

Certain Relationships and Related Party Transactions

We recognize related party transactions can present potential or actual conflicts of interest and create the appearance that decisions are based on considerations other than the best interests of us and our shareholders. Accordingly, as a general matter, it is our preference to avoid related party transactions. Nevertheless, we recognize that there are situations where related party transactions may be in, or may not be inconsistent with, the best interests of us and our shareholders, including but not limited to situations where we may obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to related parties on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. Therefore, our Board of Directors has adopted a policy for the review of related party transactions. This policy requires directors and officers to promptly report to our General Counsel all proposed or existing transactions in which the Company and they, or persons related to them, are parties or participants. Our General Counsel presents to our Governance Committee those transactions that may require disclosure pursuant to Item 404 of Regulation S-K (typically, those transactions that exceed $120,000). Our Governance Committee reviews the material facts presented and either approves or disapproves entry into the transaction. In reviewing the transaction, the Governance Committee considers the following factors, among other factors it deems appropriate: (i) whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third party under the same or similar circumstances; (ii) the extent of the related party's interest in the transaction; and (iii) the impact on a director's independence in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer.

Section 16(a) Beneficial Ownership Reporting Compliance

Based solely upon a review of our records and copies of reports on Form 3, 4 and 5 furnished to us, we believe that during and with respect to 2018, all persons subject to the reporting requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, filed the required reports on a timely basis, except for a Form 4 for Jennifer C. Landis, Senior Vice President - Chief Human Resources Officer, reporting the acquisition of 127 shares through the vesting of a restricted stock grant in the month of February 2017.

MEETINGS AND COMMITTEES OF THE BOARD

THE BOARD OF DIRECTORS

Our directors review and approve our strategic plan and oversee our management. Our Board of Directors held four in-person meetings and three telephonic meetings during 2018. Each regularly scheduled meeting of the Board includes an executive session of only independent directors. We encourage our directors to attend the annual shareholders' meeting. During 2018, each current director attended at least 75 percent of the combined total of Board meetings and Committee meetings on which the director served and all directors then serving attended the 2018 annual meeting of shareholders.

COMMITTEES OF THE BOARD

Our Board has three standing committees to facilitate and assist the Board in the execution of its responsibilities. The committees are currently the Audit Committee, the Compensation Committee and the Governance Committee. In accordance with the NYSE listing standards and our Corporate Governance Guidelines, the Audit, Compensation and Governance Committees are comprised solely of independent directors. Each committee operates under a charter, which is available on our website at www.blackhillscorp.com/investor-relations/corporate-governance and is also available in print to any shareholder who requests it. In addition, our Board creates special committees from time to time for specific purposes. Members of the committees are designated by our Board upon recommendation of the Governance Committee.

AUDIT COMMITTEE		
Committee Chair:		
Steven R. Mills	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Robert P. Otto, Mark A. Schober, John B. Vering	4	4

Primary Responsibilities

- assist the Board in fulfilling its oversight responsibility to our shareholders relating to the quality and integrity of our accounting, auditing and financial reporting practices;
- oversee the integrity of our financial statements, financial reporting process, systems of internal controls and disclosure controls regarding finance, accounting and legal compliance;
- review areas of potential significant financial risk to us;
- review consolidated financial statements and disclosures;
- appoint an independent registered public accounting firm for ratification by our shareholders;
- monitor the independence and performance of our independent registered public accountants and internal auditing department;
- pre-approve all audit and non-audit services provided by our independent registered public accountants;
- review the scope and results of the annual audit, including reports and recommendations of our independent registered public accountants;
- review the internal audit plan, results of internal audit work and our process for monitoring compliance with our Code of Business Conduct and other policies and practices established to ensure compliance with legal and regulatory requirements; and
- periodically meet, in private sessions, with our internal audit group, Chief Financial Officer, Chief Compliance Officer, other management, and our independent registered public accounting firm.

In accordance with the rules of the NYSE, all of the members of the Audit Committee are financially literate. In addition, the Board determined that Messrs. Mills, Schober and Vering have the requisite attributes of an "audit committee financial expert" as provided in regulations promulgated by the SEC, and that such attributes were acquired through relevant education and/or experience.

COMPENSATION COMMITTEE		
Committee Chair:		
Michael H. Madison	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Rebecca B. Roberts, Teresa A. Taylor, Thomas J. Zeller	2	2

Primary Responsibilities

- discharge the Board of Directors' responsibilities related to executive and director compensation philosophy, policies and programs;
- perform functions required of directors in the administration of all federal and state laws and regulations pertaining to executive employment and compensation;
- consider and recommend for approval by the Board all executive compensation programs including executive benefit programs and stock ownership plans; and
- promote an executive compensation program that supports the overall objective of enhancing shareholder value.

The Compensation Committee has authority under its charter to retain and terminate compensation consultants, outside counsel and other advisors as the Committee may deem appropriate in its sole discretion. The Committee has sole authority to approve related fees and retention terms and may delegate any of its responsibilities to subcommittees as the Committee may deem appropriate. In addition, pursuant to SEC rules and NYSE listing standards regarding the independence of compensation committee advisors, the Committee has the responsibility to consider the independence of any compensation advisor before engaging the advisor.

The Committee engaged Willis Towers Watson, an independent consulting firm, to conduct an annual review of our 2018 total compensation program for executive officers and directors. The Committee reviewed the independence of Willis Towers Watson and the individual representative of Willis Towers Watson who serves as a consultant to the Committee, in accordance with the SEC and NYSE requirements and the specific factors that the requirements cite. The Compensation Committee concluded that Willis Towers Watson is independent and Willis Towers Watson's performance of services raises no conflict of interest. The Committee's conclusion was based in part on a report that Willis Towers Watson provided to the Committee intended to reveal any potential conflicts of interest and a schedule provided by management of the type and amount of non-executive compensation services provided by Willis Towers Watson to the Company. During 2018, the cost of these non-executive compensation services was less than $25,000.

The Committee annually evaluates the CEO's performance against Board-established goals and objectives, with input from the other independent directors. Based upon the Committee's evaluation and recommendation, the independent directors of the Board set the CEO's annual compensation, including salary, bonus, incentive and equity compensation.

The CEO annually reviews the performance of each of our executive officers and presents a summary of his evaluations to the Committee. Based upon these performance reviews, market analysis conducted by the compensation consultant and discussions with our Sr. Vice President, Chief Human Resources Officer, the CEO recommends the compensation of the executive officers to the Committee. The Committee may exercise its discretion in modifying any of the recommended compensation and award levels in its review and approval process.

More information describing the Compensation Committee's processes and procedures for considering and determining executive compensation, including the role of our CEO and consultants in determining or recommending the amount or form of executive compensation, is included in the Compensation Discussion and Analysis.

In setting non-employee director compensation, the Compensation Committee recommends the form and amount of compensation to the Board of Directors, which makes the final determination. In considering and recommending the compensation of non-employee directors, the Compensation Committee considers such factors as it deems appropriate, including historical compensation information, level of compensation necessary to attract and retain non-employee directors meeting our desired qualifications and market data. In the review of director compensation in 2018, the Compensation Committee retained Willis Towers Watson to provide market information on non-employee director compensation, including compensation structure, annual board and committee retainers, committee chair fees, and stock-based compensation.

Compensation Committee Interlocks and Insider Participation. The Compensation Committee is comprised entirely of independent directors. In addition, none of our executive officers serve as a member of a board of directors or compensation committee of any entity that has one or more executive officers who serve on our Board or on our Compensation Committee.

GOVERNANCE COMMITTEE		
Committee Chair:		
Rebecca B. Roberts	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Michael H. Madison, John B. Vering, Thomas J. Zeller	3	1

Primary Responsibilities

- assess the size of the Board and membership needs and qualifications for Board membership;
- identify and recommend prospective directors to the Board to fill vacancies;
- review and evaluate director nominations submitted by shareholders, including reviewing the qualifications and independence of shareholder nominees;
- consider and recommend existing Board members to be renominated at our annual meeting of shareholders;
- consider the resignation of an incumbent director who makes a principal occupation change (including retirement) or who receives a greater number of votes "Withheld" than votes "For" in an uncontested election of directors and recommend to the Board whether to accept or reject the resignation;
- establish and review guidelines for corporate governance;
- recommend to the Board for approval committee membership and chairs of the committees;
- recommend to the Board for approval an independent director to serve as a Lead Director;
- review the independence of each director and director nominee;
- administer an annual evaluation of the performance of the Board and each Committee and a biannual evaluation of each individual director; and
- ensure that the Board oversees the evaluation and succession planning of management.

Date: 12-31-2018

LIST OF OFFICERS
BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC

OFFICER	TITLE	AREA OF RESPONSIBILITY
David R. Emery	Chairman and Chief Executive Officer	Oversees all company operations
Linden R. Evans	President and Chief Operating Officer	Oversees all utility operations, customer service
Richard W. Kinzley	Senior Vice President and Chief Financial Officer	Oversees finance, accounting, regulatory, tax
Brian G. Iverson	Senior Vice President and General Counsel	Oversees legal, compliance, internal audit
Scott A. Buchholz	Senior Vice President – Chief Information Officer	Oversees Information technology, billing systems
Jennifer C. Landis	Senior Vice President – Chief Human Resources Officer	Oversees compensation, benefits
Roxann R. Basham	Vice President – Governance and Corporate Secretary	Governance, company records, compliance
Esther J. Newbrough	Vice President and Chief Risk Officer	Corporate risk, compliance
Kimberly F. Nooney	Vice President – Corporate Controller and Treasurer	Financing, cash management, accounting, investor relations
Donna E. Genora	Vice President – Tax	Tax
Amy K. Koenig	Assistant Corporate Secretary	Governance
Ivan Vancas	Group Vice President – Natural Gas Utilities	Gas utility operations
Perry S. Krush	Vice President – Facilities	Facilities
Karen Beachy	Vice President – Growth and Strategy	Corporate strategic planning
Kyle D. White	Vice President – Regulatory Strategy	Regulatory strategy
Marne M. Jones	Vice President – Regulatory and Finance	Regulatory, finance
Mark L. Lux	Vice President – Energy Innovation	Energy innovation, growth
Marc Ostrem	Vice President – Power Delivery, Safety and Environmental	Power generation/delivery, safety, environmental
Mark E. Stege	Vice President – Customer Service	Customer service
Jodi Culp	Vice President – Gas Asset Optimization	Gas supply services
John A. Hill, Jr.	Vice President – Gas Engineering	Gas utility operations

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________ to __________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	7001 Mount Rushmore Road	IRS Identification Number
	Rapid City, South Dakota 57702	46-0458824

Registrant's telephone number, including area code
(605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2018	$3,239,030,444

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2019
Common stock, $1.00 par value	60,003,965 shares

Documents Incorporated by Reference
Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2019 Annual Meeting of Stockholders to be held on April 30, 2019, are incorporated by reference in Part III of this Form 10-K.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Year ended	December 31, 2018	December 31, 2017	December 31, 2016
	(in thousands, except per share amounts)		
Revenue	$ 1,754,268	$ 1,680,266	$ 1,538,916
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	625,610	563,288	499,132
Operations and maintenance	481,706	454,605	426,603
Depreciation, depletion and amortization	196,328	188,246	175,533
Taxes - property and production	51,746	51,578	46,160
Other operating expenses	1,841	5,813	55,307
Total operating expenses	1,357,231	1,263,530	1,202,735
Operating income	397,037	416,736	336,181
Other income (expense):			
Interest charges -			
Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	(143,720)	(140,533)	(139,091)
Allowance for funds used during construction - borrowed	2,104	2,415	2,981
Interest income	1,641	1,016	1,429
Allowance for funds used during construction - equity	619	2,321	3,270
Other income (expense), net	(1,799)	(213)	1,124
Total other income (expense)	(141,155)	(134,994)	(130,287)
Income before income taxes	255,882	281,742	205,894
Income tax benefit (expense)	23,667	(73,367)	(59,101)
Income from continuing operations	279,549	208,375	146,793
Net (loss) from discontinued operations	(6,887)	(17,099)	(64,162)
Net income	272,662	191,276	82,631
Net income attributable to noncontrolling interest	(14,220)	(14,242)	(9,661)
Net income available for common stock	$ 258,442	$ 177,034	$ 72,970
Amounts attributable to common shareholders:			
Net income from continuing operations	$ 265,329	$ 194,133	$ 137,132
Net (loss) from discontinued operations	(6,887)	(17,099)	(64,162)
Net income (loss) available for common stock	$ 258,442	$ 177,034	$ 72,970
Earnings (loss) per share of common stock, Basic -			
Earnings from continuing operations	$ 4.88	$ 3.65	$ 2.64
(Loss) from discontinued operations	(0.13)	(0.32)	(1.23)
Total earnings per share of common stock, Basic	$ 4.75	$ 3.33	$ 1.41
Earnings (loss) per share of common stock, Diluted -			
Earnings from continuing operations	$ 4.78	$ 3.52	$ 2.57
(Loss) from discontinued operations	(0.12)	(0.31)	(1.20)
Total earnings per share of common stock, Diluted	$ 4.66	$ 3.21	$ 1.37
Weighted average common shares outstanding:			
Basic	54,420	53,221	51,922
Diluted	55,486	55,120	53,271

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended	December 31, 2018	December 31, 2017	December 31, 2016
		(in thousands)	
Net income	$ 272,662	$ 191,276	$ 82,631
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $(660), $1,030 and $757, respectively)	2,155	(1,890)	(1,738)
Benefit plan liability adjustments - prior service (costs) (net of tax of $0, $0 and $107, respectively)	—	—	(247)
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(586), $(585) and $(600), respectively)	1,901	1,072	1,378
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $43, $69 and $67, respectively)	(135)	(128)	(154)
Derivative instruments designated as cash flow hedges:			
Net unrealized gains (losses) on interest rate swaps (net of tax of $0, $0 and $10,920, respectively)	—	—	(20,302)
Reclassification of net realized (gains) losses on settled/ amortized interest rate swaps (net of tax of $(599), $(1,029) and $(1,365), respectively)	2,252	1,912	2,534
Net unrealized gains (losses) on commodity derivatives (net of tax of $(228), $(135) and $212, respectively)	755	231	(361)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $(31), $154 and $4,067, respectively)	99	(516)	(6,938)
Other comprehensive income (loss), net of tax	7,027	681	(25,828)
Comprehensive income	279,689	191,957	56,803
Less: comprehensive income attributable to non-controlling interest	(14,220)	(14,242)	(9,661)
Comprehensive income available for common stock	$ 265,469	$ 177,715	$ 47,142

See Note 16 for additional disclosures related to Comprehensive Income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2018	As of December 31, 2017
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,776	$ 15,420
Restricted cash and equivalents	3,369	2,820
Accounts receivable, net	269,153	248,330
Materials, supplies and fuel	117,299	113,283
Derivative assets, current	1,500	304
Income tax receivable, net	12,978	—
Regulatory assets, current	48,776	81,016
Other current assets	29,982	25,367
Current assets held for sale	—	84,242
Total current assets	503,833	570,782
Investments	41,013	13,090
Property, plant and equipment	6,000,015	5,567,518
Less accumulated depreciation and depletion	(1,145,136)	(1,026,088)
Total property, plant and equipment, net	4,854,879	4,541,430
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	14,337	7,559
Regulatory assets, non-current	235,459	216,438
Other assets, non-current	14,352	10,149
Total other assets, non-current	1,563,602	1,533,600
TOTAL ASSETS	$ 6,963,327	$ 6,658,902

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

FORM 10K

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of	
	December 31, 2018	December 31, 2017
	(in thousands, except share amounts)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 210,609	$ 160,887
Accrued liabilities	215,501	219,462
Derivative liabilities, current	947	2,081
Accrued income tax, net	—	1,022
Regulatory liabilities, current	29,810	6,832
Notes payable	185,620	211,300
Current maturities of long-term debt	5,743	5,743
Current liabilities held for sale	—	41,774
Total current liabilities	648,230	649,101
Long-term debt, net of current maturities	2,950,835	3,109,400
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	311,331	336,520
Regulatory liabilities, non-current	510,984	478,294
Benefit plan liabilities	145,147	159,646
Other deferred credits and other liabilities	109,377	105,735
Total deferred credits and other liabilities	1,076,839	1,080,195
Commitments and contingencies (See Notes 6, 7, 8, 9, 14, 18, 19, and 20)		
Equity:		
Stockholders' equity -		
Common stock $1 par value; 100,000,000 shares authorized; issued: 60,048,567 and 53,579,986, respectively	60,049	53,580
Additional paid-in capital	1,450,569	1,150,285
Retained earnings	700,396	548,617
Treasury stock at cost - 44,253 and 39,064, respectively	(2,510)	(2,306)
Accumulated other comprehensive income (loss)	(26,916)	(41,202)
Total stockholders' equity	2,181,588	1,708,974
Noncontrolling interest	105,835	111,232
Total equity	2,287,423	1,820,206
TOTAL LIABILITIES AND TOTAL EQUITY	$ 6,963,327	$ 6,658,902

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2018	December 31, 2017	December 31, 2016
	(in thousands)		
Operating activities:			
Net income	$ 272,662	$ 191,276	$ 82,631
Loss from discontinued operations, net of tax	6,887	17,099	64,162
Income (loss) from continuing operations	279,549	208,375	146,793
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	196,328	188,246	175,533
Deferred financing cost amortization	7,845	8,261	6,180
Stock compensation	12,390	7,626	10,885
Deferred income taxes	(24,239)	80,992	82,704
Employee benefit plans	14,068	10,141	14,291
Other adjustments, net	5,836	(4,773)	(5,519)
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(2,919)	(10,089)	1,211
Accounts receivable and other current assets	(45,966)	4,534	(27,172)
Accounts payable and other current liabilities	5,305	(28,222)	(33,023)
Regulatory assets	33,608	(15,407)	3,614
Regulatory liabilities	18,533	(4,536)	(14,082)
Contributions to defined benefit pension plans	(12,700)	(27,700)	(14,200)
Interest rate swap settlement	—	—	(28,820)
Other operating activities, net	6,689	(8,418)	(660)
Net cash provided by operating activities of continuing operations	494,327	409,030	317,735
Net cash provided by (used in) operating activities of discontinued operations	(5,516)	19,231	2,744
Net cash provided by operating activities	488,811	428,261	320,479
Investing activities:			
Property, plant and equipment additions	(457,524)	(326,010)	(454,952)
Acquisition of net assets, net of long-term debt assumed	—	—	(1,124,238)
Purchase of investment	(24,429)	—	—
Other investing activities	(4,281)	1,011	(562)
Net cash (used in) investing activities of continuing operations	(486,234)	(324,999)	(1,579,752)
Net cash provided by (used in) investing activities of discontinued operations	20,385	7,881	(8,413)
Net cash (used in) investing activities	(465,849)	(317,118)	(1,588,165)
Financing activities:			
Dividends paid on common stock	(106,591)	(96,744)	(87,570)
Common stock issued	300,834	4,408	121,619
Net increase (decrease) in commercial paper and short-term borrowings	(25,680)	114,700	19,800
Long-term debt - issuance	700,000	—	1,767,608
Long-term debt - repayments	(854,743)	(105,743)	(1,164,308)
Sale of noncontrolling interest	—	—	216,370
Distributions to noncontrolling interests	(19,617)	(18,397)	(9,561)
Other financing activities	(11,260)	(6,919)	(22,960)
Net cash provided by (used in) financing activities	(17,057)	(108,695)	840,998
Net change in cash, restricted cash and cash equivalents	5,905	2,448	(426,688)
Cash, restricted cash and cash equivalents beginning of year	18,240	15,792	442,480
Cash, restricted cash and cash equivalents end of year	$ 24,145	$ 18,240	$ 15,792

See Note 17 for supplemental disclosure of cash flow information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

Balance Sheet CY & PY and PY Dec w Chg Amt (All Products)
Business Unit: BH KANSAS GAS UTILITY CO LLC
HTD December, 2018

Run For: Scenario, All Resource Codes, All Allocation Types

Data from the PSGLFERC Essbase Cube

	Y2018	Y2017	
Account Description	I-T-D(December)	I-T-D(December)	Change from Prior Year End
ASSETS:			
UTILITY PLANT:			
101000 PLANT IN SERVICE	260,976,839	254,317,172	6,659,667
101001 PLANT IN SERVICE INTANGIBLES	3,205,293	3,205,293	0
101340 NON UTILITY PLANT	(2,125,888)	(2,127,678)	1,790
101999 GAAP TO FERC PLANT	1,002,864	1,475,469	(472,605)
106000 COMPLETE NOT CLASSIFIED IN CPR	20,807,508	5,640,023	15,167,485
114000 PLANT ACQUISITION ADJUSTMENTS	5,234,286	5,234,286	0
114003 PLANT ACQUISITION ADJ - OTHER	(124,688)	(124,688)	0
114999 GAAP TO FERC ACQ ADJ	(792,564)	(792,564)	0
118990 BHUHC UTILITY PLANT ALLOC	12,628,522	11,586,204	1,042,318
118999 COMMON UTILITY PLANT ALLOC	2,918,804	3,459,213	(540,409)
UTILITY PLANT	303,730,976	281,872,730	21,858,246
107000 CONSTRUCTION WORK IN-PROGRESS	653,174	2,661,477	(2,008,303)
CWIP Construction Work In Progress	653,174	2,661,477	(2,008,303)
TOTAL UTILITY PLANT	304,384,150	284,534,207	19,849,943
108000 PLT IN SERV-ACCUM DEPREC-ORIG	(92,396,826)	(57,385,286)	(35,011,540)
108001 RETIREMENT WORK IN PROGRESS	61,858	44,506	17,352
108002 PLT IN SERV-ACCUM DEPR-REM COS	(3,688,614)	(2,957,868)	(730,746)
108003 PLT IN SERV-ACCUM DEPREC-SALV	0	(851,940)	851,940
108004 ACCUM DEPR/RET/REM/SALV	0	(30,358,548)	30,358,548
108005 ACCUM DEPR/RET/REM/SALVT&WE	0	(825,152)	825,152
108006 ACCUM AMORT - INTANGIBLES	(2,177,588)	(2,075,913)	(101,675)
108340 PLT IN SERV_ACC AMORT NONUTILITY	668,182	594,058	74,124
108999 GAAP TO FERC ACCUM DEPR	(156,864)	(156,864)	0
111000 PLT IN SERV-ACC AMORT -REGUTIL	(19,387)	(46,244)	26,857
119990 BHUHC ACCUM DEPR-ALLOC	(4,924,869)	(4,742,473)	(182,396)
119998 UHC ACC DEPR CUR ALLOC	(958,951)	(997,126)	38,175
119999 COMMON UTIL-ACC DEPR-ALLOC	(1,452,649)	(1,815,054)	362,405
ACCUM DEPRECIATION	(105,045,707)	(101,573,903)	(3,471,804)
NET UTILITY PLANT	199,338,443	182,960,304	16,378,139
OTHER PROPERY AND INVESTMENTS:			
121000 NONUTILITY PROPERTY	2,125,888	2,127,678	(1,790)
121990 BHUHC NON UTILITY PLANT ALLOC	560,796	440,230	120,566
121999 NON UTILITY PLANT ALLOC	153,621	166,796	(13,175)
NON UTILITY PROPERTY	2,840,306	2,734,705	105,601
122000 NON-UTIL PLT-ACCUM DEPR-ORIG	(668,182)	(594,058)	(74,124)
122990 BHUHC ACCUM DEPR-NON UTIL PLT	(306,469)	(267,611)	(38,858)
122999 NON UTIL-ACCDEPR-ALLOC	(76,455)	(87,518)	11,063
ACCUM PROV DEPREC ACCUM PROV FOR DEPRECIATION	(1,051,106)	(949,188)	(101,918)
TTL OTH PROPERTY & INVESTMENT	1,789,200	1,785,517	3,683

Balance Sheet CY & PY and PY Dec w Chg Amt (All Products)
Business Unit: BH KANSAS GAS UTILITY CO LLC
HTD December, 2018

Run For: Scenario, All Resource Codes, All Allocation Types

Data from the PSGLFERC Essbase Cube

Account Description	Y2018 I-T-D(December)	Y2017 I-T-D(December)	Change from Prior Year End
CURRENT AND ACCRUED ASSETS:			
131148 WELLS FARGO OPER CASH	(1,036,028)	0	(1,036,028)
131149 WELLS FARGO OPER CASH - DISBUR	(129,388)	0	(129,388)
131150 WELLS FARGO UTIL DEPOSITORY	1,088,410	606,332	482,078
131154 WF BHE RM	1,020	27,102	(26,082)
131221 WELLS FARGO PMT SVCS	76,047	111,522	(35,475)
131233 WELLS FARGO EFT/CHECKLINE	(72)	0	(72)
131234 WELLS FARGO COLLECTION AGENCY	453	0	453
CASH ACCOUNTS	441	744,956	(744,515)
142000 CUSTOMER ACCTS RECEIVABLE CIS	8,358,146	7,053,521	1,304,625
142002 CUSTOMER A/R MERC	248,556	288,316	(39,760)
142006 CUSTOMER A/R INSTALL	281,510	288,791	(7,281)
CUST ACCT RECEIVABLE CUSTOMER ACCOUNTS RECEIVABLE	8,888,211	7,630,629	1,257,582
143003 A/R CONTRIB IN AID OF CONSTRUC	58,920	50,157	8,763
143008 A/R DAMAGE CLAIMS	67,646	41,248	26,398
143012 A/R OTHER EMPLOYEE LOANS	4,910	5,080	(170)
143028 A/R TO BE COLLECTED FOR OTHERS	1,101	1,101	0
143060 A/R SHORT TERM NEG BAL RECLASS	264,683	86,093	178,590
OTHER ACCTS RECVBL OTHER ACCOUNTS RECEIVABLE	397,260	183,679	213,581
144000 ACCUM PROV FOR UNCOLL ACCTS	(367,408)	(315,094)	(52,314)
ACCUM PROV-UNCOLL ACCUM PROV FOR UNCOLLECTIBLE	(367,408)	(315,094)	(52,314)
146000 I/C ACCOUNTS RECEIVABLE	3,150,122	1,987,808	1,162,314
ACCTS REC INTER CO ACCTS RECEIVABLE INTER COMPANY	3,150,122	1,987,808	1,162,314
154000 MATERIALS AND SUPPLIES GENERAL	1,320,769	822,657	498,112
154003 INVENTORY MANUAL	81,083	34,490	46,593
154007 INVENTORY-TRANSFERS IN TRANSIT	0	0	0
PLANT MATERIAL & OP PLANT MATERIALS & OP SUPPLIES	1,401,851	857,147	544,704
163000 STORES EXPENSE UNDISTRIBUTED-	438,015	263,084	174,931
STORES EXP UNDIST STORES EXPENSE UNDISTRIBUTED	438,015	263,084	174,931
164100 GAS STORED UNDERGROUND-	(632,211)	(934,913)	302,702
164110 GAS STORED UNDERGROUND	3,568,576	4,409,633	(841,057)
GAS STORED UG CRNT GAS STORED UNDERGROUND CRNT	2,936,366	3,474,721	(538,355)
165002 PREPAID INSURANCE	28,377	26,845	1,532
165007 PREPAID FEDERAL TAXES	0	296,825	(296,825)
165012 PREPAID OTHR	2,275	0	2,275
165180 PREPAID STATE TAXES	15,690	15,690	0
PREPAYMENTS	46,342	339,360	(293,018)
173000 ACCRUED UNBILLED REVENUES	8,105,742	7,521,819	583,923
ACCD UTILITY REVENUE ACCRUED UTILITY REVENUES	8,105,742	7,521,819	583,923
174000 EXCHANGE GAS RECEIVABLE	131,902	21,108	110,794
MISC CRNT ACCD ASSTS MISC CURRENT & ACCURED ASSETS	131,902	21,108	110,794
TTL CURRENT & ACCRUED ASSETS	25,128,844	22,709,217	2,419,627

Balance Sheet CY & PY and PY Dec w Chg Amt (All Products)
Business Unit: BH KANSAS GAS UTILITY CO LLC
HTD December, 2018

Run For: Scenario, All Resource Codes, All Allocation Types

Data from the PSGLFERC Essbase Cube

	Y2018	Y2017	
Account Description	I-T-D(December)	I-T-D(December)	Change from Prior Year End
DEFFERRED DEBITS:			
182300 REG ASSET OTHER	0	169,831	(169,831)
182305 REG ASSET ARO	0	1	(1)
182310 REG ASSET PENSION PRIOR SVC	41,296	257,757	(216,461)
182315 REG ASSET RETIREE HC	491,762	672,084	(180,322)
182316 REG ASSET PENSION	4,601,192	4,625,583	(24,391)
182361 REG ASSET ST RECLASS	1,235,550	1,868,138	(632,588)
182375 REG ASSET LT OTHER INC TAX	842,661	564,209	278,452
OTHER REG ASSETS OTHER REGULATORY ASSETS	7,212,461	8,157,602	(945,141)
183200 PRELIM SURVEY CHARGES GENERAL	0	226,221	(226,221)
PRELIM SURV & INVEST PRELIM SURVEY & INVESTIGATION	0	226,221	(226,221)
184000 FLEET/TRANSPORTATION CLEARING	55,126	54,715	411
184003 FIELD ENGINEERING CLEARING	82,140	176,391	(94,251)
184004 Field Eng Clearing Transmission	19	996	(977)
CLEARING ACCOUNTS	137,285	232,101	(94,816)
186001 MISC DEFERRED DEBITS-IN PROCES	76,618	76,618	0
MISC DEFERRED DEBITS	76,618	76,618	0
190520 DEFERRED TAX ASSET LT	5,698,471	3,388,703	2,309,768
190599 DEF TAX ASSET STATE INC TAX LT	206,471	1,699	204,772
ACCUM DEF INC TAXES ACCUM DEFERRED INCOME TAXES	5,904,942	3,390,403	2,514,539
191100 UNREC PGA ACT-GEN SYSTEM REAL	0	0	0
191300 UNREC PGA CST UNBILLED	(4,820,359)	(4,438,838)	(381,521)
191541 UNREC PGA CST PND KS	(115,485)	311,735	(427,220)
191549 UNREC PGA CAPACITY RELEASE	(509,041)	(364,365)	(144,676)
191560 UNREC PGA CAP REL-SH SHAREDREV	254,521	182,182	72,339
191600 REG ASST GCA MTHLY ACCRUAL	2,763,914	3,484,529	(720,615)
UNREC PURCH GAS UNRECOVERED PURCHASED GAS	(2,426,450)	(824,757)	(1,601,693)
DEFERRED DEBITS	10,904,856	11,258,188	(353,332)
TOTAL ASSETS AND OTHER DEBITS:	237,161,343	218,713,226	18,448,117
LIABILITIES AND SHAREHOLDERS EQUITY:			
PROPRIETARY CAPITAL:			
211001 ADDL PAID IN CAPITAL	61,514,021	55,514,021	6,000,000
OTH PAID IN CAPITAL OTHER PAID IN CAPITAL	61,514,021	55,514,021	6,000,000
216000 RETAINED EARNINGS GENERAL	2,151,348	1,356,601	794,747
216999 GAAP TO FERC RETAINED EARNINGS	(253,662)	66,297	(319,959)
RETAINED EARNINGS	1,897,686	1,422,898	474,788
TOTAL PROPRIETARY CAPITAL	63,411,707	56,936,919	6,474,788

Balance Sheet CY & PY and PY Dec w Chg Amt (All Products)
Business Unit: BH KANSAS GAS UTILITY CO LLC
HTD December, 2018

Run For: Scenario, All Resource Codes, All Allocation Types

Data from the PSGLFERC Essbase Cube

Account Description	Y2018 I-T-D(December)	Y2017 I-T-D(December)	Change from Prior Year End
LONG-TERM DEBT:			
OTHER NON-CURRENT LIABILITIES:			
228202 RESERVE WORKERS' COMPENSATION	706,452	1,020,581	(314,129)
228204 RESERVE MEDICAL	123,701	114,845	8,856
ACCUM PROV INJRY DAM ACCUM PROV INJURIES & DAMAGES	830,154	1,135,426	(305,272)
228302 BENEFITS ACCRUAL PENSION	2,921,063	3,237,860	(316,797)
ACCUM PROV PEN & BEN ACCUM PROV PENSIONS & BENFITS	2,921,063	3,237,860	(316,797)
229001 BILLINGS COLL SUBJECT TO REFUN	13,887	0	13,887
ACCUM PROV RATE RFND ACCUM PROV FOR RATE REFUNDS	13,887	0	13,887
TTL OTR NONCRNT LIAB TTL OTH NONCRNT LIABILITIES	3,765,104	4,373,286	(608,182)
CURRENT AND ACCRUED LIABILITIES:			
232000 AP PEOPLESOFT SUBLEDGER	914,438	690,541	223,897
232005 A/P PO ACCRUAL	40,247	12,471	27,776
232006 A/P GAS PURCHASES ESTIMATED	9,296,991	7,525,273	1,771,718
232009 A/P MANUAL	633,145	1,275,227	(642,082)
232014 A/P WH FLEX 125 DEPENDENT	2,226	1,998	228
232016 A/P WH HEALTH INSURANCE	18,403	13,263	5,140
232017 A/P WH PAC	40	37	3
232021 A/P WH EMPL DONATIONS	907	870	37
232022 A/P WH GARNISHMENTS	2,403	3,107	(704)
232023 A/P WH LIFE INSURANCE	4,664	4,158	506
232026 A/P CUSTOMER CARE	1,176	1,245	(69)
ACCTS PAYABLE ACCOUNTS PAYABLE	10,914,639	9,528,190	1,386,449
233000 I/C NOTES PAYABLE TO UMP	6,367,650	20,543,790	(14,176,140)
233053 I/C NOTES PAYABLE AFFILIATE	75,000,000	65,000,000	10,000,000
233100 I/C INTEREST PAYABLE TO UMP	16,355	28,663	(12,308)
233153 I/C INTEREST PAYABLE AFFILIATE	291,142	258,638	32,504
NOTE PAY INTER CO NOTES PAYABLE INTER COMPANY	81,675,147	85,831,091	(4,155,944)
234000 I/C ACCOUNTS PAYABLE	16,494,457	13,907,165	2,587,292
234222 CIS+ ACCOUNT BALANCE TRANSFERS	0	208	(208)
ACCT PAY INTER CO ACCOUNTS PAYABLE INTER COMPANY	16,494,457	13,907,374	2,587,083
235000 CUSTOMER DEPOSITS-	1,425,901	1,385,757	40,144
CUSTOMER DEPOSITS	1,425,901	1,385,757	40,144
236000 ACCRUED INCOME TAXES FEDERAL	6,122	0	6,122
236004 ACCRUED PROPERTY TAXES	2,111,305	2,204,281	(92,976)
236010 ACCRUED FICA TAX EMPLOYER	105,523	89,123	16,400
236011 ACCRUED FUTA TAX	1,262	613	649
236012 ACCRUED SUTA TAX	282	88	194
TAXES ACCRUED	2,224,494	2,294,105	(69,611)
237002 ACCRUED INT CUSTOMER DEPO	0	0	0

Balance Sheet CY & PY and PY Dec w Chg Amt (All Products)

Business Unit: BH KANSAS GAS UTILITY CO LLC

HTD December, 2018

Run For: Scenario, All Resource Codes, All Allocation Types

Data from the PSGLFERC Essbase Cube

Account Description	Y2018 I-T-D(December)	Y2017 I-T-D(December)	Change from Prior Year End
INTEREST ACCRUED	0	0	0
241000 FICA WITHHOLDING TAXES PAYABLE	29,558	25,923	3,635
241001 FEDERAL WITHHOLDING TAXES PAYB	41,717	46,948	(5,231)
241002 TAX COLLECTION PAY CITY FRANCH	654,638	561,295	93,343
241004 STATE SALES AND USE TAX	230,226	190,390	39,836
241006 STATE WITHHOLDING TAXES PAYABL	16,465	14,392	2,073
TAX COLLECTED PAY TAX COLLECTIONS PAYABLE	972,604	838,948	133,656
242003 ACCRUED BENEFITS COMP ABSENCES	314,024	266,536	47,488
242013 ACCRUED BENEFITS 401K	108,770	81,727	27,043
242014 ACCRUED BONUS OTHER	22,899	0	22,899
242019 ACCRUED ENERGY AID ASSISTANCE	29,137	29,496	(359)
242020 ACCRUED CUSTOMER IMBALANCES	196,972	30,751	166,221
242028 ACCRD UNCL CHECKS/ESCHEATS	340	271	69
242041 ACCRUED INCENTIVE	947,128	666,627	280,501
242045 ACCRUED PAYROLL	255,626	191,166	64,460
242046 ACCRUED EE REIMBURSED EXP	13,180	19,873	(6,693)
242052 ACCRUED LT PERFORMANCE PLAN	10,067	7,171	2,896
242500 ACCRUED LONG TERM LIABILITIES	269,409	161,836	107,573
242560 ACCRD LIAB ST NEG BAL RECLASS	468	0	468
242999 ACCRUED OTHER	2,194,802	1,269,723	925,079
MISC CRNT ACCD LIAB MISC CURRENT & ACCRUED LIAB	4,362,821	2,725,176	1,637,645
TOTAL CURRENT & ACCRUED LIAB	118,070,063	116,510,641	1,559,422
DEFFERED CREDITS:			
252000 CUSTOMER ADVANCES FOR CONST	151,522	208,633	(57,111)
252001 CUST ADVANCE FOR CONST CURRENT	41,877	82,397	(40,520)
CUST ADV FOR CONSTR CUSTOMER ADVANCE CONSTRUCTION	193,398	291,030	(97,632)
253520 FIN 48 LIABILITY	1	1	0
253700 OTH DEF CR ENERGY ASST PRGM	120,553	129,438	(8,885)
253999 OTH DEF CR OTHER	500,500	250,000	250,500
OTH DEFERRED CREDITS OTHER DEFERRED CREDITS	621,054	379,439	241,615
254000 REG LIAB OTHER LT	2,472,745	1,624,410	848,335
254001 REG LIAB EMISSIONS	0	0	0
254004 REG LIAB ACL PIPE REPL RIDR KS	0	0	0
254015 REG LIAB FLOWBACK EXCESS DEFTX	16,820,329	15,163,687	1,656,642
254020 REG LIAB PGA CR BAL RECLASS	0	0	0
254070 REG LIAB LT NEG BAL RECLASS	1,299,560	0	1,299,560
254100 REG LIAB LT RETIREE HC INC TAX	148,324	204,515	(56,191)
254200 REG LIABILITY LT PENSION INC TAX	1,400,255	1,485,999	(85,744)
254386 REG LIAB RETIREE MED TRACKER	321,065	229,713	91,352
OTH REGULATORY LIAB OTHER REGULATORY LIABILITIES	22,462,278	18,708,325	3,753,953
282100 DEF TAX PROPERTY LT	21,463,174	19,141,147	2,322,027

Balance Sheet CY & PY and PY Dec w Chg Amt (All Products)
Business Unit: BH KANSAS GAS UTILITY CO LLC
HTD December, 2018

Run For: Scenario, All Resource Codes, All Allocation Types

Data from the PSGLFERC Essbase Cube

Account Description	Y2018 I-T-D(December)	Y2017 I-T-D(December)	Change from Prior Year End
282599 DEF TAX LIAB STATE PROP LT	2,890,131	2,770,607	119,524
ACCUM DEF INC TAX PR ACCUM DEF INCOME TAXES PROPTY	24,353,306	21,911,754	2,441,552
283440 DEFERRED TAX LIAB LT	(4,874,603)	(5,848,332)	973,729
283534 DEF TAX LIAB STATE INC TAX LT	(634,166)	(831,721)	197,555
283998 GAAP TO FERC-DEF TAX LT LIAB	290,178	290,178	0
283999 GAAP TO FERC-DEFTX LIAB-STATE	16,920	16,920	0
ACCUM DEF INC TAX OT ACCUM DEF INCOME TAX OTHER	(5,201,671)	(6,372,955)	1,171,284
TOTAL DEFERRED CREDITS	42,428,365	34,917,593	7,510,772
UNDIST YTD NET INCOME	9,486,107	5,974,788	3,511,319
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY:	237,161,346	218,713,227	18,448,119
Balance Sheet Tie Out (Assets=Liabilities)	(3)	(1)	(1)

Report: Bal Sheet - Detail w Totals YTD & LYD FERC Page: 1 of 1

Printed: May 14, 2019 01:36 PM

Data from the PSGLFERC Essbase Cube

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________________ to _________________
Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	7001 Mount Rushmore Road	IRS Identification Number
	Rapid City, South Dakota 57702	46-0458824

Registrant's telephone number, including area code
(605) 721-1700
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2018 $3,239,030,444

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2019
Common stock, $1.00 par value	60,003,965 shares

Documents Incorporated by Reference
Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2019 Annual Meeting of Stockholders to be held on April 30, 2019, are incorporated by reference in Part III of this Form 10-K.

(6) LONG-TERM DEBT

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

	Due Date	Interest Rate at December 31, 2018	Balance Outstanding December 31, 2018	Balance Outstanding December 31, 2017
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$ 525,000	$ 525,000
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Remarketable junior subordinated notes [b]	November 1, 2028	3.50%	—	299,000
Senior unsecured notes due 2019	January 11, 2019	2.50%	—	250,000
Senior unsecured notes due 2026	January 15, 2026	3.95%	300,000	300,000
Senior unsecured notes due 2027	January 15, 2027	3.15%	400,000	400,000
Senior unsecured notes due 2033	May 1, 2033	4.35%	400,000	—
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300,000	300,000
Corporate term loan due 2019	August 9, 2019	2.55%	—	300,000
Corporate term loan due 2020 [a]	July 30, 2020	3.16%	300,000	—
Corporate term loan due 2021	June 7, 2021	2.32%	12,921	18,664
Total Corporate debt			2,437,921	2,592,664
Less unamortized debt discount			(5,122)	(3,808)
Total Corporate debt, net			2,432,799	2,588,856
Electric Utilities				
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	75,000
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 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021 [c]	September 1, 2021	1.73%	7,000	7,000
Industrial development revenue bonds due 2027 [c]	March 1, 2027	1.73%	10,000	10,000
Series 94A Debt, variable rate [c]	June 1, 2024	1.93%	2,855	2,855
Total Electric Utilities debt			544,855	544,855
Less unamortized debt discount			(86)	(90)
Total Electric Utilities debt, net			544,769	544,765
Total long-term debt			2,977,568	3,133,621
Less current maturities			5,743	5,743
Less unamortized deferred financing costs [d]			20,990	18,478
Long-term debt, net of current maturities and deferred financing costs			$ 2,950,835	$ 3,109,400

(a) Variable interest rate, based on LIBOR plus a spread.
(b) See Note 12 for RSN details.
(c) Variable interest rate.
(d) Includes deferred financing costs associated with our Revolving Credit Facility of $2.3 million and $1.7 million as of December 31, 2018 and December 31, 2017, respectively.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2019	$	5,743
2020	$	505,743
2021	$	8,435
2022	$	—
2023	$	525,000
Thereafter	$	1,937,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2018.

Substantially all of the tangible utility property of South Dakota Electric and Wyoming Electric is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of South Dakota Electric and Wyoming Electric may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by South Dakota Electric and Wyoming Electric are callable, but are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Debt Transactions

On December 12, 2018, we paid off the $250 million, 2.5% senior unsecured notes due January 11, 2019. Proceeds from the November 1, 2018 Equity Unit conversion were used to pay off this debt.

On August 17, 2018, we issued $400 million principal amount, 4.350% senior unsecured notes due 2033. A portion of these notes were issued in a private exchange that resulted in the retirement of all $299 million principal amount of our RSNs due 2028. The remainder of the notes were sold for cash in a public offering, with the net proceeds being used to pay down short-term debt.

The issuance of these new senior notes was the culmination of a series of transactions that also included the contractually required remarketing of such RSNs on behalf of the holders of our Equity Units, with the proceeds being deposited as collateral to secure the obligations of those holders under the purchase contracts included in the Equity Units (see Note 12). As a result of the remarketing, the annual interest rate on such RSNs was automatically reset to 4.579% (however, because the RSNs were then immediately retired, no interest accrued at this reset rate).

On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at December 31, 2018, will now mature on July 30, 2020 and has substantially similar terms and covenants as the amended and restated Revolving Credit Facility. The interest cost associated with this term loan is determined based upon our corporate credit rating from S&P, Fitch, and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings and Eurodollar borrowings were 0.000% and 0.700%, respectively, at December 31, 2018.

On May 16, 2017, we paid down $50 million on our Corporate term loan due August 9, 2019. On July 17, 2017, we paid down an additional $50 million on the same term loan. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan.

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income (Loss) were as follows (in thousands):

Deferred Financing Costs Remaining at	Amortization Expense for the years ended December 31,		
December 31, 2018	2018	2017	2016
$ 20,990	$ 2,829	$ 3,349	$ 3,861

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs. In addition, the agreements governing our equity units contain restrictions on the payment of cash dividends upon any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the RSNs included in such equity units. As of December 31, 2018, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2018:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2018, the restricted net assets at our Electric and Gas Utilities were approximately $257 million.

(7) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of December 31, 2018, we were in compliance with all of these financial covenants.

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	Balance Outstanding at	
	December 31, 2018	December 31, 2017
CP Program	$ 185,620	$ 211,300

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our Corporate credit rating from S&P, Fitch, and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, at December 31, 2018. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at December 31, 2018. Margins and the commitment fee rate decreased in August 2018 due to our upgraded credit rating from S&P.

We have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net (payments) under the CP Program during 2018 were $(26) million and our notes outstanding as of December 31, 2018 were $186 million. As of December 31, 2018, the weighted average interest rate on CP Program borrowings was 2.88%.
As of December 31, 2018 and December 31, 2017, we had outstanding letters of credit totaling approximately $22 million and approximately $27 million, respectively.

Total accumulated deferred financing costs on the Revolving Credit Facility of $6.7 million are being amortized over its estimated useful life and were included in Interest expense on the accompanying Consolidated Statements of Income (Loss). See Note 6 above for additional details.

Debt Covenants

Under our Revolving Credit Facility and term loan agreements we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit and certain guarantees issued by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interest in subsidiaries.

Our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	At December 31, 2018	Covenant Requirement at December 31, 2018	
Consolidated Indebtedness to Capitalization Ratio	59%	Less than	65%

(8) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to reclamation of coal mining sites in the Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment, retirement of gas pipelines at our Gas Utilities and asbestos at our Electric and Gas Utilities. We periodically review and update estimated costs related to these asset retirement obligations. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

The following tables present the details of AROs which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2017	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates (b)	December 31, 2018
Electric Utilities	$ 6,287	$ —	$ —	$ 269	$ 2	$ 6,558
Gas Utilities	33,238	152	—	1,237	—	34,627
Mining	12,499	—	(4)	649	2,471	15,615
Total	$ 52,024	$ 152	$ (4)	$ 2,155	$ 2,473	$ 56,800

	December 31, 2016	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates (a)	December 31, 2017
Electric Utilities	$ 4,661	$ —	$ (4)	$ 268	$ 1,362	$ 6,287
Gas Utilities	29,775	—	—	1,142	2,321	33,238
Mining	12,440	—	(107)	651	(485)	12,499
Total	$ 46,876	$ —	$ (111)	$ 2,061	$ 3,198	$ 52,024

(a) The Gas Utilities' Revision to Prior Estimates represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.
(b) The increase in the Mining Revision to Prior Estimates was primarily driven by higher costs associated with back-filling the pit with overburden removed during the mining process.

We also have legally required AROs related to certain assets within our electric transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a liability for the cost of these obligations cannot be measured at this time.

We had identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells. These obligations were classified as held for sale at December 31, 2017. See Note 21.

Kansas Ring Fencing Compliance
Financial Ratios
Total Debt to Total Capitalization

Black Hills Corporation
(in thousands)

<u>Attachment</u>

06-GIMX-181-GIV

		2018
	Numerator	
	Notes payable	185,620
+	Commercial paper	-
+	Current maturities	5,743
+	Current capitalized lease obligations	-
+	Long term debt	2,950,835
+	Capitalized lease obligations	-
+	Total OBS Debt	94,490
		3,236,688
	Denominator	
	Notes payable	185,620
+	Commercial paper	-
+	Current maturities	5,743
+	Current capitalized lease obligations	-
+	Long Term debt	2,950,835
+	Capitalized lease obligations	-
+	Common equity	2,287,423
+	Total OBS Debt	94,490
		5,524,111
		58.59%

Source: 2018 Black Hills Corporation Form 10-K

Kansas Ring Fencing Compliance
Financial Ratios
Funds From Operations Interest Coverage

Black Hills Corporation
(in thousands)

Attachment

06-GIMX-181-GIV

		2018
	Numerator	
	Net income from continuing operations	258,442
+	Depreciation, depletion & amortization	196,328
+	Deferred income taxes (net)	(24,207)
+	Investment tax credit amortization	(32)
-	AFUDC - debt	2,104
-	AFUDC - equity	619
+	(Income) loss from equity investments	-
+	(Gain) loss on property	-
+	Deferred income taxes adjusted	-
	Total Funds from operations (FFO)	427,808
+	Cash interest paid (net of interest capitalized)	137,965
+	AFUDC - debt	2,104
-	Interest expense adjustment	-
+	Interest on OBS debt	-
		567,877
	Denominator	
	Interest expense (net)	143,720
-	Interest expense adjustment	-
+	AFDC - debt	2,104
+	Interest on OBS debt	-
		145,824
		3.8943

Source: 2018 Black Hills Corporation Form 10-K

Kansas Ring Fencing Compliance
Financial Ratios
Funds From Operations as a % of Total Debt

Black Hills Corporation
(in thousands)

Attachment

06-GIMX-181-GIV

		2018
	Numerator	
	Net income from continuing operations	258,442
+	Depreciation, depletion & amortization	196,328
+	Deferred income taxes (net)	(24,207)
+	Investment tax credit amortization	(32)
-	AFUDC - debt	2,104
-	AFUDC - equity	619
+	(Income) loss from equity investments	-
+	(Gain) loss on property	-
+	Deferred income taxes adjusted	-
	Total Funds from operations (FFO)	427,808
+	Depreciation adjustment for Operating Leases	-
		427,808
	Denominator	
	Notes payable	185,620
+	Commercial paper	-
+	Current maturities	5,743
+	Current capitalized lease obligation	-
+	Long term debt	2,950,835
+		-
+	Total OBS Debt	94,490
		3,236,688
		13.22%

Source: 2018 Black Hills Corporation Form 10-K

Income Statement - Prior Year Comparison - FERC Reporting Acct Detail
Business Unit: BH KANSAS GAS UTILITY CO LLC
December, 2018 YTD

Run For: All Products, All Resource Codes, All Allocation Types

	Year-To-Date 2018	Year-To-Date 2017	Year-To-Date Variance
480000 RESIDENTIAL GAS SALES	65,902,805	60,169,683	5,733,122
480001 RESIDENTIAL UNBILLED GAS	325,952	(717,196)	1,043,148
480005 RESIDENTIAL GAS ALT REV	32,702	2,323,815	(2,291,112)
481000 COMMERCIAL FIRM GAS REVENUE	21,078,021	19,824,869	1,253,152
481001 COMMERCIAL FIRM UNBIL GAS REV	62,764	(460,300)	523,064
481005 COMMERCIAL GAS ALT REV	(19,944)	661,220	(681,164)
481010 COMMERCIAL INTERR GAS REVENUE	697,327	793,189	(95,862)
481100 INDUSTRIAL FIRM GAS REVENUE	433,379	349,927	83,451
481101 INDUSTRIAL FIRM UNBIL GAS REV	161,910	(325,894)	487,804
481105 INDUSTRIAL GAS ALT REV	39	1,256	(1,217)
481110 INDUSTRIAL INTERR GAS REVENUE	8,767,420	8,441,992	325,428
487000 FORFEITED DISC/LATE PMT GAS	392,190	368,791	23,399
488000 MISC SERVICE REV GAS	727,109	759,874	(32,765)
489301 COMM FIRM TRANSPORT REV-DISTRB	3,035,611	2,516,366	519,245
489302 IND FIRM TRANSPORT REV-DISTRB	956,988	796,767	160,221
489303 COMM INTER TRANSPRT REV-DISTRB	305,147	254,228	50,920
489304 IND INTER TRANSPRT REV-DISTRB	3,193,476	2,824,516	368,960
489305 UNBILLED TRANSPORT REV-DISTRB	33,000	101,000	(68,000)
496000 PROVISION FOR RATE REFUNDS	(1,755,481)	0	(1,755,481)
495000 Other Revenue And Royalties	610,487	189,898	420,589
TOTAL OPERATING REVENUE	**104,940,903**	**98,874,002**	**6,066,901**
850000 TRANS OPS SUPERV & ENG	87,778	119,579	(31,801)
851000 TRANS SYS CONTR & LOAD DISPATC	252	0	252
856000 TRANS MAINS EXPENSE	59,856	72,734	(12,878)
857000 TRANS MEAS & REGUL STATION EXP	9,516	20,431	(10,915)
870000 DIST OPS SUPERVISION AND ENGIN	1,007,782	994,167	13,615
874002 ROUTINE LEAK SURV MAINS & SVCS	545,823	593,010	(47,187)
874001 PERF DISTRIB MAIN LOCATES-GAS	834,461	753,746	80,715
874000 OPER/INSPECT UG DIST MAINS-GAS	784,454	830,103	(45,649)
875001 OPERATE/INSPECT FARM TAPS(O&M)	125,460	96,381	29,079
877000 DIST MEAS & REG STAT - CITY GA	96,495	46,580	49,915
876000 DIST MEAS & REG STAT - INDUS	29,394	103,288	(73,894)
875000 DIST MEAS & REG STAT - GENERAL	195,458	128,026	67,432
878001 PERF CONNECTS/DISCON/RECON-GAS	515,442	755,981	(240,539)
878000 OPER/INSP MTRS COLLECT DATAGAS	243,044	359,485	(116,442)
871000 DIST LOAD DISPATCHING	125	11	114
879000 DIST CUSTOMER INSTALLATIONS	424,203	476,988	(52,785)
881000 DIST OPER RENTS	3,766	7,157	(3,391)
880001 CO USED GAS O&M OFFSET	15,006	15,135	(130)
880000 DIST OPS OTHER EXPENSE	3,362,088	2,882,318	479,770
873000 DISTR FUEL/POWER COMPR STATION	0	353	(353)
872000 DIST COMPR STAT LABR & EXP	0	1,340	(1,340)

Income Statement - Prior Year Comparison - FERC Reporting Acct Detail
Business Unit: BH KANSAS GAS UTILITY CO LLC
December, 2018 YTD

Run For: All Products, All Resource Codes, All Allocation Types

	Year-To-Date 2018	Year-To-Date 2017	Year-To-Date Variance
852000 COMMUNICATION SYS EXP	0	15	(15)
859000 OTHER TRANS OPS EXP	155,843	114,531	41,312
860000 TRANSM RENT	24	(479)	503
804000 NATURAL GAS CITY GATE PURCHASE	52,002,120	48,630,919	3,371,201
805000 OTHER GAS PURCHASES	(3,985)	269	(4,254)
805001 COST OF UNBILLED REVENUE	381,521	(954,274)	1,335,795
805100 PURCHASED GAS COST ADJUSTMENTS	560,748	1,532,528	(971,780)
805200 FINANCIAL GAS COST ADJ	26,582	(508,858)	535,440
808100 GAS WITHDRAWN FROM STORAGE DR	5,004,900	4,668,450	336,450
808200 GAS DELIVERED TO STORAGE CR	(4,466,545)	(4,928,588)	462,043
812000 GAS USED FOR OTHER UTILITY OPS	(13,399)	(12,526)	(873)
813000 OTHER GAS SUPPLY EXPENSES	0	(1,348)	1,348
814000 UG STORAGE OPS SUPERV & ENG	0	0	0
TOTAL ELECTRIC/GAS OPERATING EXPENSE	61,988,211	56,797,452	5,190,759
901000 CUST ACCTS SUPERVISION	280,242	394,982	(114,740)
902002 OTHER METER READING EXPENSES	18,098	25,460	(7,362)
902001 RE-READ METERS	4,557	12,233	(7,676)
902000 READ METERS	347,989	313,643	34,346
903002 PROC/COLLECT DELINQUENT ACCTS	213,681	195,309	18,373
903001 PROCESS CUSTOMER REMITTANCES	49,567	56,097	(6,530)
903000 CUST ACCTS RECORDS & COLLECTIO	2,499,356	2,379,433	119,924
904000 UNCOLLECTIBLE ACCOUNTS	496,281	619,709	(123,427)
905000 MISC CUSTOMER ACCOUNTS	84,737	130,077	(45,340)
907000 CUSTOMER SERVICE SUPERVISION	39,220	60,178	(20,958)
908000 CUSTOMER ASSISTANCE EXP	171,035	83,368	87,668
909000 INFORMATIONAL & INSTRUCT ADS	12,711	10,784	1,927
910000 MISC CUST SERVICE & INFO	20,701	42,955	(22,254)
912000 SALES DEMONSTRATING & SELLING	137,752	41,105	96,647
916000 MISCELLANOUS SALES EXPENSES	268	1,366	(1,098)
911000 SALES SUPERVERION	20,086	17,179	2,907
913000 SALES ADVERTISING EXPENSES	127,630	68,930	58,700
920000 ADMIN AND GENERAL SALARIES	10,796,516	9,814,855	981,660
920999 LABOR OVERHEAD OFFSET	(3,808,286)	(3,592,797)	(215,489)
921000 OFFICE SUPPLIES & EXPENSE	1,730,163	1,763,544	(33,381)
922000 ADMIN EXP TRANS CREDIT	(1,270,128)	(1,054,326)	(215,802)
923000 OUTSIDE SERVICES	1,199,645	1,049,140	150,505
924000 PROPERTY INSURANCE	3,990	3,967	23
925000 INJURIES AND DAMAGES	116,730	639,181	(522,450)
926000 EMPLOYEE PENSIONS & BENEFITS	5,613,131	5,507,224	105,908
926040 EMPLOYEE PENSIONS/BEN NON SEVC	68,540	0	68,540
926949 Ben Non SevC Loading Offset	(727)	0	(727)
926999 BENEFIT OVERHEAD OFFSET	(5,552,348)	(5,074,544)	(477,804)
928000 REGULATORY COMMISSION EXP	157,241	361,327	(204,086)

Income Statement - Prior Year Comparison - FERC Reporting Acct Detail
Business Unit: BH KANSAS GAS UTILITY CO LLC
December, 2018 YTD

Run For: All Products, All Resource Codes, All Allocation Types

	Year-To-Date 2018	Year-To-Date 2017	Year-To-Date Variance
929000 DUPLICATE CHARGES - CREDIT	0	0	0
930100 GENERAL ADVERTISING	60,675	41,375	19,300
930200 MISCELLANEOUS GENERAL EXP	261,253	207,934	53,319
930299 GAAP TO FERC BANK FEES	139,511	155,828	(16,317)
931000 A & G RENTS	162,001	197,946	(35,945)
931001 I/C RENT EXPENSE	544,535	98,775	445,760
TOTAL A&G & OTHER EXPENSES	14,746,356	14,572,236	174,120
TOTAL OPERATING EXPENSE	**76,734,567**	**71,369,688**	**5,364,879**
863000 TRANS MAINT OF MAINS	137,922	121,648	16,274
865000 TRANS MNT MEAS & REG STAT EQU	19,105	33,513	(14,409)
867000 TRANS MAINT OF OTHER EQUIP	6,345	2,614	3,730
861000 TRANS MAINT SUPERV & ENGIN	47,475	83,503	(36,028)
888000 DIST MAINT COMPR STATION EQUIP	3,062	3,399	(337)
885000 DIST MAINT SUPER & ENG	150,663	206,589	(55,926)
889001 MAINTAIN FARM TAPS (O&M)	688	7,429	(6,740)
891000 DS MNT MS & REG STAT EQ-CITY G	121,902	212,335	(90,433)
890000 DS MNT MEAS & REG STAT EQ-IND	47,599	35,012	12,586
889000 DS MNT MEAS & REG STAT EQ-GEN	138,728	157,384	(18,656)
894000 DIST MAINT OF OTHER EQUIP	8,687	5,908	2,779
892000 DIST MAINT OF SERVICES	165,152	121,045	44,106
887001 PERFMAINT_3RDPRTYDMG-UGDISTGAS	(9,816)	(982)	(8,834)
887000 PERF UG DISTRIB LINE MAINT-GAS	431,380	519,873	(88,493)
886000 DIST MAINT STRUCT & IMPROVE	2,997	5,977	(2,979)
893000 DIST MAINT METERS & HSE REGS	726,975	306,721	420,254
TOTAL MAINTENANCE EXPENSES	1,998,865	1,821,969	176,896
935000 MAINTENANCE GENERAL PLANT	633,650	569,222	64,428
TOTAL A&G MAINTENANCE EXPENSES	633,650	569,222	64,428
TOTAL MAINTENANCE EXPENSE	**2,632,515**	**2,391,191**	**241,323**
403000 DEPRECIATION	6,791,376	6,456,230	335,146
403340 DEPRECIATION NONREG	(42,990)	(42,331)	(659)
DEPREC EXPENSE DEPRECIATION EXPENSE	6,748,386	6,413,899	334,487
405000 AMORTIZATION EXPENSE	101,675	101,997	(322)
AMORT & DEPL UTILTY AMORT & DEPL OF UTILITY PLANT	101,675	101,997	(322)
406000 AMORTIZATION PLANT ACQUIS ADJ	0	37,613	(37,613)
AMORT UTILITY PLT AQ AMORT UTILITY PLANT ACQ ADJ	0	37,613	(37,613)
408100 Taxes Oth-Than Income Taxes	1,145,944	1,203,810	(57,866)
408130 TOTI-PROPERTY TAXES	3,637,109	3,786,334	(149,226)
408199 TAXES OTI CAPITAL OFFSET	(1,205,590)	(1,135,957)	(69,634)
TAXES OTHER THAN INC TAXES OTHER THAN INCOME	3,577,463	3,854,187	(276,725)
409100 CURRENT FED INC TAX	1,555,734	4,823,300	(3,267,566)
INC TAXES FEDERAL INCOME TAXES FEDERAL	1,555,734	4,823,300	(3,267,566)

Income Statement - Prior Year Comparison - FERC Reporting Acct Detail
Business Unit: BH KANSAS GAS UTILITY CO LLC
December, 2018 YTD

Run For: All Products, All Resource Codes, All Allocation Types

	Year-To-Date 2018	Year-To-Date 2017	Year-To-Date Variance
409101 CURRENT STATE INC TAX	(73,874)	(73,920)	45
INC TAXES OTHER INCOME TAXES OTHER	(73,874)	(73,920)	45
410101 DEFERRED CURRENT STATE INC TAX	1,626,116	1,163,098	463,017
410100 DEFERRED CURRENT FED INC TAX	11,322,901	19,677,427	(8,354,526)
410110 EXCESS DEFERRED TAX	164,367	0	164,367
PROV DEF INC TAX PROVISION FOR DEF INCOME TAX	13,113,384	20,840,526	(7,727,142)
411101 DEF INC TAX ST CR OPERATING	(1,288,152)	(754,445)	(533,707)
411100 DEF INC TAX FED CR OPERATING	(9,462,760)	(18,057,661)	8,594,901
411110 EXCESS DEFERRED TAX - PLANT	(164,367)	0	(164,367)
LESS PROV DEF INC TX LESS PROV DEF INCOME TAX CRED	(10,915,279)	(18,812,106)	7,896,827
OTHER OPERATING EXPENSES	**14,107,488**	**17,185,497**	**(3,078,009)**
TOTAL UTILITY OPERATING EXPENSES	93,474,569	90,946,377	2,528,193
NET UTILITY OPERATING INCOME	**11,466,334**	**7,927,626**	**3,538,709**
415000 MERCHANDISE REVENUES	921,213	847,633	73,581
REV MERCH JOBBING REVENUE MERCH JOBBING CONTRACT	921,213	847,633	73,581
416000 EXP MERCH JOBBING & CONTRACT	408,404	433,609	(25,205)
LESS COST & EXP MERC LESS COST & EXPENSE MERCH JOB	408,404	433,609	(25,205)
417000 NONUTILITY REVENUES	5,148,043	4,834,576	313,467
417057 OTHER REVENUE AND ROYALTIES NR	1,295,632	1,019,230	276,402
REV NON UTILITY OPS REVENUE NON UTILITY OPERATIONS	6,443,675	5,853,806	589,869
417100 NONUTILITY EXPENSES - COS	3,179,443	2,874,529	304,914
417101 NONUTILITY EXP - OTHER O&M	598,311	512,777	85,534
417158 NONUTILITY OPS EXPENSE OTHER	111,729	41,952	69,777
417160 NONUTILITY SELLING EXPENSE	81,689	168,198	(86,509)
417161 NONUTILITY ADMIN & GENERAL	(37,132)	(102,064)	64,933
417162 ADMIN AND GEN-EMPL BENEFITS	21,243	19,764	1,480
417165 EXP FOR UNCOLLECT ACCT NONREG	67,936	63,783	4,153
417180 NONUTILITY DEPRECIATION EXP	79,970	75,067	4,902
LESS EXP NON UTILITY LESS EXPENSE NON UTILITY OPS	4,103,189	3,654,005	449,184
419000 INTEREST INCOME - 3RD PARTY	1,805	780	1,025
419052 I/C INT INC ALLOC FROM BHSC	0	293	(293)
419053 I/C UMP INT INC FROM AFFILIATE	188,911	56,494	132,417
419055 I/C INTEREST INCOME AFFILIATE	0	(2,812)	2,812
INT & DIVIDEND INC INTEREST & DIVIDEND INCOME	190,716	54,755	135,961
421000 Misc Nonoperating Income	13,348	13,614	(266)
MISC NON OP INCOME MISC NON OPERATING INCOME	13,348	13,614	(266)
421198 O&M GAIN ON SALE OF ASSET OP	2,259	304,428	(302,168)
421999 GAAP TO FERC GN ON ASSET SALE	0	(319,959)	319,959
GAIN DISPO PROPERTY GAIN ON DISPOSITION PROPERTY	2,259	(15,531)	17,791
TOTAL OTHER INCOME	3,059,619	2,666,662	392,957
426100 MISC NONOPER DONATIONS	126,590	164,611	(38,021)

Income Statement - Prior Year Comparison - FERC Reporting Acct Detail
Business Unit: BH KANSAS GAS UTILITY CO LLC
December, 2018 YTD

Run For: All Products, All Resource Codes, All Allocation Types

	Year-To-Date 2018	Year-To-Date 2017	Year-To-Date Variance
DONATIONS	126,590	164,611	(38,021)
426300 MISC NONOPER PENALTIES	1,508	529	979
PENALTIES	1,508	529	979
426400 MISC NONOPER CIVIC & POLITICAL	110,017	98,788	11,229
EXP CIVIC POLITICAL EXP CIVIC POLITICAL & RELATED	110,017	98,788	11,229
426500 MISC NONOPER OTHER	224,615	71,136	153,479
426501 MISC OPERATING	48	0	48
OTHER DEDUCTIONS	224,663	71,136	153,527
TTL OTH INC DEDUCT TOTAL OTHER INCOME DEDUCTIONS	462,779	335,064	127,715
408200 TAXES OTHR TN INCTAX NON UTIL	59,620	56,902	2,719
TAXES OTHER TAXES ON OTHER INCOME	59,620	56,902	2,719
409200 CURR INC TAX FED NONOPERATING	519,439	792,858	(273,418)
INC TAX FED OTHER FED INC TAX OTHER INC DED	519,439	792,858	(273,418)
409201 CURR INC TAX ST NONOPERATING	73,874	73,920	(45)
INC TAX STATE OTHER STATE INC TAX OTHER INC & DED	73,874	73,920	(45)
410200 DEFERRED INCOME TAXES - OTHER	(36,271)	0	(36,271)
410201 DEFERRED STATE INCOME TAXES - Non op	172,717	0	172,717
DEF INC TAX OTHER DEF TAX PROV OTHER INC & DED	136,446	0	136,446
TAXES OTH INC & DED TAXES OTHER INCOME & DEDUCTION	789,381	923,679	(134,298)
NET OTH INC & DED NET OTHER INCOME & DEDUCTIONS	1,807,459	1,407,919	399,540
TOTAL OTHER INCOME & DEDUCTIONS	**1,807,459**	**1,407,919**	**399,540**
430000 I/C INTEREST EXPENSE TO UMP	357,665	197,836	159,830
430002 I/C INT EXP ALLOC FROM BHSC	9,045	5,826	3,219
430003 I/C UMP INT EXP TO AFFILIATE	196,781	56,811	139,970
430005 I/C INTEREST EXPENSE AFFILIATE	3,398,917	3,317,700	81,217
430999 GAAP TO FERC - BANK FEES	(139,511)	(155,828)	16,317
INT DEBT ASSOC COMP INTEREST ON DEBT ASSOC COMPANY	3,822,897	3,422,344	400,552
431000 INTEREST EXPENSE - 3RD PARTY	15,138	10,792	4,346
431001 INTEREST ON CUSTOMER DEPOSITS	22,613	11,164	11,449
431500 CAPITALIZED INTEREST	(12,103)	(18,279)	6,176
OTH INTEREST EXPENSE OTHER INTEREST EXPENSE	25,648	3,677	21,971
432000 AFUDC DEBT	(60,858)	(65,265)	4,407
LESS AFUDC BORROWED	(60,858)	(65,265)	4,407
NET INTEREST CHRGS NET INTEREST CHARGES	3,787,687	3,360,757	426,930
NET INTEREST CHARGES	**3,787,687**	**3,360,757**	**426,930**
NI BEFORE EXTRAORDINARY ITEMS	**9,486,107**	**5,974,788**	**3,511,319**
EXTRAORDINARY ITEMS	0	0	0
TOTAL NET INCOME	**9,486,107**	**5,974,788**	**3,511,319**

Report: Income Stmt - QTD & YTD w Pr Yr for FERC Rpt Detail
Printed: May 16, 2019 02:58 PM
Data from the PSGLFERC Essbase Cube

BLACK HILLS CORPORATION
LIST OF CREDIT RATING AGENCIES AND EQUITY ANALYST REPORTS RECEIVED
(May 23, 2018 to May 22, 2019)

Bank	Analyst	Date
Credit Suisse Securities	Michael Weinstein	5/23/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	5/24/2018
Wells Fargo Capital Markets	Sarah Akers	5/24/2018
Credit Suisse Securities	Michael Weinstein	6/4/2018
RBC Capital Markets	Insoo Kim	6/5/2018
Credit Suisse Securities	Michael Weinstein	7/2/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	7/12/2018
Scotia Howard Weil	Andrew Weisel	7/24/2018
RBC Capital Markets	Shelby Tucker	8/6/2018
Credit Suisse Securities	Michael Weinstein	8/8/2018
Wells Fargo Capital Markets	Sarah Akers	8/8/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	8/9/2018
S&P		8/9/2018
Scotia Howard Weil	Andrew Weisel	8/13/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	10/8/2018
Williams Capital	Christopher Ellinghaus	10/15/2018
Credit Suisse Securities	Michael Weinstein	10/17/2018
Fitch		10/18/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	10/30/2018
Credit Suisse Securities	Michael Weinstein	10/30/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	11/1/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	11/2/2018
Credit Suisse Securities	Michael Weinstein	11/5/2018
RBC Capital Markets	Shelby Tucker	11/5/2018
Scotia Howard Weil	Andrew Weisel	11/5/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	11/6/2018
Scotia Howard Weil	Andrew Weisel	11/6/2018
Wells Fargo Capital Markets	Sarah Akers	11/6/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	11/7/2018
Credit Suisse Securities	Michael Weinstein	11/7/2018
Wells Fargo Capital Markets	Sarah Akers	11/7/2018
Williams Capital	Christopher Ellinghaus	11/7/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	11/9/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	11/13/2018
Credit Suisse Securities	Michael Weinstein	11/13/2018
RBC Capital Markets	Shelby Tucker	11/13/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	11/27/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	12/4/2018
Credit Suisse Securities	Michael Weinstein	12/4/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	12/10/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	12/12/2018
Scotia Howard Weil	Andrew Weisel	12/12/2018
Scotia Howard Weil	Andrew Weisel	12/12/2018
Moody's		12/12/2018
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	12/18/2018
Credit Suisse Securities	Michael Weinstein	1/31/2019
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	2/4/2019
Williams Capital	Christopher Ellinghaus	2/6/2019
Credit Suisse Securities	Michael Weinstein	2/7/2019
RBC Capital Markets	Shelby Tucker	2/8/2019
Wells Fargo Capital Markets	Sarah Akers	2/8/2019
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	2/11/2019
Credit Suisse Securities	Michael Weinstein	2/11/2019
Scotia Howard Weil	Andrew Weisel	2/11/2019
RBC Capital Markets	Shelby Tucker	2/13/2019
S&P		2/28/2019
Credit Suisse Securities	Michael Weinstein	3/4/2019
Scotia Howard Weil	Andrew Weisel	3/6/2019
Credit Suisse Securities	Michael Weinstein	3/7/2019
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	3/29/2019
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	4/9/2019
Scotia Howard Weil	Andrew Weisel	4/15/2019
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	4/17/2019
Scotia Howard Weil	Andrew Weisel	4/18/2019
Credit Suisse Securities	Michael Weinstein	4/21/2019
Credit Suisse Securities	Michael Weinstein	5/2/2019
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	5/3/2019
RBC Capital Markets	Shelby Tucker	5/3/2019
Scotia Howard Weil	Andrew Weisel	5/3/2019
Wells Fargo Capital Markets	Sarah Akers	5/3/2019
Bank of Americal Merrill Lynch	Julien Dumoulin-Smith	5/5/2019
Scotia Howard Weil	Andrew Weisel	5/5/2019
Scotia Howard Weil	Andrew Weisel	5/8/2019