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, 2021
Or

☐ 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 IRS Identification Number 46-0458824

7001 Mount Rushmore Road
Rapid City, South Dakota 57702
Registrant's telephone number (605) 721-1700

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common stock of $1.00 par value	BKH	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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter, June 30, 2021, was $4,135,954,577

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, 2022
Common stock, $1.00 par value	64,738,725 shares

Documents Incorporated by Reference
Portions of the registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2022 Annual Meeting of Stockholders to be held on April 26, 2022, are incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Arkansas (doing business as Black Hills Energy).
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
BHC	Black Hills Corporation; the Company
BHSC	Black Hills Service Company, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC, a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing wholesale electric capacity and energy primarily to our affiliate utilities.
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Services	Black Hills Energy Services Company, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas commodity supply for the Choice Gas Programs (doing business as Black Hills Energy).
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy). Also known as South Dakota Electric.
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Busch Ranch I	The 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and Black Hills Electric Generation. Colorado Electric and Black Hills Electric Generation each have a 50% ownership interest in the wind farm. Black Hills Electric Generation provides its share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037.
Busch Ranch II	The 59.4 MW wind farm near Pueblo, Colorado owned by Black Hills Electric Generation to provide wind energy to Colorado Electric through a PPA expiring in November 2044.
CARES Act	Coronavirus Aid, Relief, and Economic Security Act, signed on March 27, 2020, which is a tax and spending package intended to provide additional economic relief and address the impact of the COVID-19 pandemic.
CFTC	United States Commodity Futures Trading Commission
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service in the Cheyenne, Wyoming area (doing business as Black Hills Energy). Also known as Wyoming Electric.
Cheyenne Prairie	Cheyenne Prairie Generating Station serves the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 40 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 100 MW unit that is jointly-owned by Wyoming Electric (42 MW) and South Dakota Electric (58 MW).
Chief Operating Decision Maker (CODM)	Chief Executive Officer
Choice Gas Program	Regulator-approved programs in Wyoming and Nebraska that allow certain utility customers to select their natural gas commodity supplier, providing the unbundling of the commodity service from the distribution delivery service.
City of Colorado Springs	Colorado Springs, Colorado
City of Gillette	Gillette, Wyoming

Colorado Electric	Black Hills Colorado Electric, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing electric service to customers in Colorado (doing business as Black Hills Energy).
Colorado Gas	Black Hills Colorado Gas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Colorado (doing business as Black Hills Energy).
Common Use System	The Common Use System is a jointly operated transmission system we participate in with Basin Electric Power Cooperative and Powder River Energy Corporation. The Common Use System provides transmission service over these utilities' combined 230-kilovolt (kV) and limited 69-kV transmission facilities within areas of southwestern South Dakota and northeastern Wyoming.
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by capital at such time. Capital being consolidated net-worth (excluding non-controlling interest) plus consolidated indebtedness (including letters of credit and certain guarantees issued) as defined within the current Revolving Credit Facility.
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
Corriedale	The 52.5 MW wind farm near Cheyenne, Wyoming, jointly owned by South Dakota Electric (32.5 MW) and Wyoming Electric (20 MW), serving as the dedicated wind energy supply to the Renewable Ready program.
COVID-19	The official name for the 2019 novel coronavirus disease announced on February 11, 2020, by the World Health Organization, that is causing a global pandemic.
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CT	Combustion Turbine
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.
Cushion Gas	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.
CVA	Credit Valuation Adjustment
DC	Direct Current
Dividend Payout Ratio	Annual dividends paid on common stock divided by net income from continuing operations available for common stock
DRSPP	Dividend Reinvestment and Stock Purchase Plan
DSM	Demand Side Management
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu).
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measure.
ECA	Energy Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Purchased energy that costs less than that produced with the utilities' owned generation.
EECR	Energy Efficiency Cost Recovery is an adjustment mechanism that allows us to recover from customers the costs associated with providing energy efficiency programs.
EIA	Environmental Improvement Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible investments in, and expense related to, new environmental measures.
Energy Transition	The global energy sector's shift from fossil-based systems of energy production and consumption, including oil, natural gas and coal to renewable energy sources like wind and solar, as well as battery storage solutions.
EPA	United States Environmental Protection Agency
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of gas and certain services through to customers.

GHG	Greenhouse gases
Global Settlement	Settlement with a utility's commission where the revenue requirement is agreed upon, but the specific adjustments used by each party to arrive at the amount are not specified in public rate orders.
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
HomeServe	We offer HomeServe products to our natural gas residential customers interested in purchasing additional home repair service plans.
Integrated Generation	Non-regulated power generation and mining businesses that are vertically integrated within our Electric Utilities segment.
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Iowa (doing business as Black Hills Energy).
IPP	Independent Power Producer
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
ITC	Investment Tax Credit
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Kansas (doing business as Black Hills Energy).
KCC	Kansas Corporation Commission
kV	Kilovolt
LIBOR	London Interbank Offered Rate
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MDU	Montana-Dakota Utilities Co., a subsidiary of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MSHA	United States Department of Labor's Mine Safety and Health Administration
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Nebraska (doing business as Black Hills Energy).
Neil Simpson II	A mine-mouth, coal-fired power plant owned and operated by South Dakota Electric with a total capacity of 90 MW located at our Gillette, Wyoming energy complex.
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen oxide
NOL	Net Operating Loss
NPSC	Nebraska Public Service Commission
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	United States Department of Labor's Occupational Safety & Health Administration
OSM	United States Department of the Interior's Office of Surface Mining
PacifiCorp	PacifiCorp, a wholly owned subsidiary of MidAmerican Energy Holdings Company, itself an affiliate of Berkshire Hathaway.

PCA	Power Cost Adjustment is an annual adjustment mechanism that allows us to pass a portion of prudently-incurred delivered power costs, including fuel, purchased capacity and energy, and transmission costs, through to customers.
PCCA	Power Capacity Cost Adjustment is an annual adjustment that allows us to pass the prudently-incurred purchased capacity costs, incremental to costs included in base rates, through to customers.
Peak View	The 60.8 MW wind farm owned by Colorado Electric.
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PSA	Power Sales Agreement
PTC	Production Tax Credit
Pueblo Airport Generation	The 440 MW combined cycle gas-fired power generation plants jointly owned by Colorado Electric (240 MW) and Black Hills Colorado IPP (200 MW). Black Hills Colorado IPP owns and operates this facility. The plants commenced operation on January 1, 2012.
PUHCA 2005	Public Utility Holding Company Act of 2005
Ready	The Company's branding platform which emphasizes that we will 1) prioritize our customers; 2) act as a thoughtful, responsible leader; 3) listen first and lead with a focus on relationships; and 4) be creative in our approach to solutions.
Ready Wyoming	A 285-mile, multi-phase transmission expansion project in Wyoming. This transmission project will serve the growing needs of customers by enhancing resiliency of Wyoming Electric's overall electric system and expanding access to power markets and renewable resources. The project will help Wyoming Electric maintain top-quartile reliability and enable economic development in the Cheyenne, Wyoming region.
Renewable Ready	Voluntary renewable energy subscription program for large commercial, industrial and governmental customers in South Dakota and Wyoming.
RESA	Renewable Energy Standard Adjustment is an incremental retail rate limited to 2% for Colorado Electric customers that provides funding for renewable energy projects and programs to comply with Colorado's Renewable Energy Standard.
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which was amended and restated on July 19, 2021, and now terminates on July 19, 2026.
RMNG	Rocky Mountain Natural Gas LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas transmission and wholesale services in western Colorado (doing business as Black Hills Energy).
RTO	Regional Transmission Organization
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Service Guard Comfort Plan	Appliance protection plan that provides home appliance repair services through on-going monthly service agreements to residential utility customers.
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	S&P Global Ratings, a division of S&P Global Inc.
SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
South Dakota Electric	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in Montana, South Dakota and Wyoming (doing business as Black Hills Energy).
SPP	Southwest Power Pool, a regional transmission organization (RTO) that oversees the bulk electric grid and wholesale power market in the central United States.
SSIR	System Safety and Integrity Rider
System Peak Demand	Represents the highest point of retail customer usage for a single hour.
TCA	Transmission Cost Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible transmission investments prior to the next rate review.
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
Tech Services	Non-regulated product lines delivered by our Utilities that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.
Top of Iowa	Northern Iowa Windpower, LLC, a 87.1 MW wind farm located near Joice, Iowa, owned by Black Hills Electric Generation and operated by a third-party. We sell the wind energy generated in the MISO market.

TFA	Transmission Facility Adjustment is an annual adjustment mechanism that allows us to recover charges for qualifying new and modified transmission facilities from customers.
Transmission Tie	South Dakota Electric owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western and eastern United States, respectively. Basin Electric Power Cooperative owns the remaining ownership percentage. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West.
TSA	United States Department of Homeland Security's Transportation Security Administration
Utilities	Black Hills' Electric and Gas Utilities
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
Wind Capacity Factor	Measures the amount of electricity a wind turbine produces in a given time period relative to its maximum potential
Winter Storm Uri	February 2021 winter weather event that caused extreme cold temperatures in the central United States and led to unprecedented fluctuations in customer demand and market pricing for natural gas and energy.
Working Capacity	Total gas storage capacity minus cushion gas
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing coal supply primarily to five on-site, mine-mouth generating facilities (doing business as Black Hills Energy).
Wygen I	A mine-mouth, coal-fired generating facility with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. Black Hills Wyoming owns 76.5% of the facility and Municipal Energy Agency of Nebraska (MEAN) owns the remaining 23.5%.
Wygen II	A mine-mouth, coal-fired power plant owned by Wyoming Electric with a total capacity of 95 MW located at our Gillette, Wyoming energy complex.
Wygen III	A mine-mouth, coal-fired power plant operated by South Dakota Electric with a total capacity of 116 MW located at our Gillette, Wyoming energy complex. South Dakota Electric owns 52% of the power plant, MDU owns 25% and the City of Gillette owns the remaining 23%.
Wyodak Plant	The 402.3 MW mine-mouth, coal-fired generating facility located at our Gillette, Wyoming energy complex, jointly owned by PacifiCorp (80%) and South Dakota Electric (20%). Our WRDC mine supplies all of the fuel for the facility.
Wyoming Electric	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in the Cheyenne, Wyoming area (doing business as Black Hills Energy).
Wyoming Gas	Black Hills Wyoming Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Wyoming (doing business as Black Hills Energy).

WEBSITE ACCESS TO REPORTS

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

FORWARD-LOOKING INFORMATION

This Form 10-K contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, such as the COVID-19 pandemic or Winter Storm Uri, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Annual Report on Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEM 1. BUSINESS

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 (incorporated in South Dakota in 1941).

We operate our business in the United States, reporting our operating results through our Electric Utilities and Gas Utilities segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other. In the fourth quarter of 2021, we integrated our power generation and mining businesses within the Electric Utilities segment. The alignment is consistent with the current way our CODM evaluates the performance of the business and makes decisions related to the allocation of resources. Comparative periods presented reflect this change. See further segment information in Note 16 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 218,000 electric utility customers in Colorado, Montana, South Dakota and Wyoming. We also own and operate non-regulated power generation and mining assets that are vertically integrated into our Electric Utilities. Our Electric Utilities own 1,481.5 MW of generation and 8,899 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,094,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate 4,732 miles of intrastate gas transmission pipelines and 41,644 miles of gas distribution mains and service lines, six natural gas storage sites, more than 50,000 horsepower of compression and over 515 miles of gathering lines.

Electric Utilities

We conduct electric utility operations through our Colorado, South Dakota and Wyoming subsidiaries. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our retail customers. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services to our retail customers under the Service Guard Comfort Plan and Tech Services.

Additionally, we own and operate non-regulated power generation and mining assets that are vertically integrated into and primarily support our Electric Utilities. Nearly all of these operations are located at our electric generating complexes and are physically integrated into our Electric Utilities’ operations.

	As of December 31,		
Retail Customers	2021	2020	2019
Residential	186,852	184,872	183,232
Commercial	30,326	30,225	29,921
Industrial	81	83	83
Other	1,010	1,017	1,024
Total Electric Retail Customers at End of Year	218,269	216,197	214,260

	As of December 31,		
Retail Customers	2021	2020	2019
Colorado Electric	99,709	98,735	97,890
South Dakota Electric	74,509	73,700	73,052
Wyoming Electric	44,051	43,762	43,318
Total Electric Retail Customers at End of Year	218,269	216,197	214,260

Capacity and Demand. System Peak Demand for the Electric Utilities' retail customers for each of the last three years are listed below:

	System Peak Demand (in MW)					
	2021		2020		2019	
	Summer	Winter	Summer	Winter	Summer	Winter
Colorado Electric	407	279	401	297	422	297
South Dakota Electric	397	299	378	304	335	320
Wyoming Electric	274	246	271	246	265	247

As of December 31, 2021, our Electric Utilities' ownership interests in electric generating plants were as follows:

Unit	Fuel Type	Location	Ownership Interest % [d]	Owned Nameplate Capacity (MW)	In Service Date
Colorado Electric:					
Busch Ranch I [a]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View [b]	Wind	Pueblo, Colorado	100%	60.8	2016
Pueblo Airport Generation #1-2	Gas	Pueblo, Colorado	100%	200.0	2011
Pueblo Airport Generation CT #6	Gas	Pueblo, Colorado	100%	40.0	2016
AIP Diesel	Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1 and #3-5	Oil	Pueblo, Colorado	100%	8.0	1964
Diesel #1-5	Oil	Rocky Ford, Colorado	100%	10.0	1964
South Dakota Electric:					
Cheyenne Prairie	Gas	Cheyenne, Wyoming	58%	58.0	2014
Corriedale [c]	Wind	Cheyenne, Wyoming	62%	32.5	2020
Wygen III	Coal	Gillette, Wyoming	52%	60.3	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak Plant	Coal	Gillette, Wyoming	20%	80.5	1978
Neil Simpson CT	Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, South Dakota	100%	100.0	1977-1979
Wyoming Electric:					
Cheyenne Prairie	Gas	Cheyenne, Wyoming	42%	42.0	2014
Cheyenne Prairie CT	Gas	Cheyenne, Wyoming	100%	40.0	2014
Corriedale [c]	Wind	Cheyenne, Wyoming	38%	20.0	2020
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Integrated Generation:					
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation #4-5	Gas	Pueblo, Colorado	50.1% [e]	200.0	2012
Busch Ranch I [a]	Wind	Pueblo, Colorado	50%	14.5	2012
Busch Ranch II [c]	Wind	Pueblo, Colorado	100%	59.4	2019
Top of Iowa [c]	Wind	Joice, Iowa	100%	87.1	2019
Total MW Capacity				1,481.5	

(a) In 2013, Busch Ranch I was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act.
(b) The Peak View facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning November 2016. The PTCs for this facility flow back to customers through a rider mechanism as a reduction to Colorado Electric's margins.
(c) This facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning on the date the facility was originally placed in service.
(d) Jointly owned facilities are discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.
(e) In 2016, Black Hills Electric Generation sold a 49.9% non-controlling interest in Black Hills Colorado IPP to a third party. See Note 12 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Our Electric Utilities' power supply by resource as a percent of the total power supply for our energy needs for the years ended December 31 was as follows:

Power Supply	2021	2020	2019
Coal	34.2 %	40.3 %	40.0 %
Natural Gas and Diesel Oil [(a)]	24.4	25.0	22.2
Wind	11.3	8.8	5.8
Total Generated	69.9	74.1	68.0
Coal, Natural Gas, Oil and Other Market Purchases	25.1	21.1	29.1
Wind Purchases	5.0	4.8	2.9
Total Purchased	30.1	25.9	32.0
Total	100.0 %	100.0 %	100.0 %

(a) The diesel-fueled generating units are generally used as supplemental peaking units. Power generated from these units, as a percentage of total power supply, was 0.0%, 0.0% and 0.1% for the years ended December 31, 2021, 2020, and 2019, respectively.

Our Electric Utilities' weighted average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 were as follows:

Fuel and Purchased Power (dollars per MWh)	2021	2020	2019
Coal	$ 11.55	$ 11.38	$ 12.42
Natural Gas and Diesel Oil [(a)]	33.65	8.59	11.04
Total Generated Weighted Average Fuel Cost	17.40	9.09	12.48
Coal, Natural Gas, Oil and Other Market Purchases [(a)]	64.85	40.80	44.16
Wind Purchases	34.69	42.06	49.19
Total Purchased Power Weighted Average Cost	59.84	41.03	44.62
Total Weighted Average Fuel and Purchased Power Cost	$ 30.17	$ 17.36	$ 22.76

(a) The 2021 increase in prices paid for fuel and purchased power was primarily driven by unforeseeable and unprecedented market prices for natural gas and electricity during Winter Storm Uri. See further information in the Recent Developments section of Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Power Purchase and Power Sales Agreements. We have executed various PPAs to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation, which include long-term related party agreements with our non-regulated power generation businesses. We also have various long-term PSAs. Key contracts are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Coal Mining. We own and operate a single coal mine through our WRDC subsidiary. We surface mine, process and sell low-sulfur sub-bituminous coal at our mine located immediately adjacent to our Gillette energy complex in the Powder River Basin in northeastern Wyoming, where our five coal-fired power plants are located. We produced approximately 3.5 million tons of coal in 2021.

The mine provides low-sulfur coal directly to these five power plants via a conveyor belt system, minimizing transportation costs. On average, the fuel can be delivered to the adjacent power plants at less than $1.00 per MMBtu, providing very cost competitive fuel to our power plants when compared to alternatives. Nearly all of the mine's production is sold to our on-site generation facilities under long-term supply contracts.

As of December 31, 2021, we estimated our recoverable reserves to be approximately 178 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 reserve life is equal to approximately 51 years at the current production levels.

Transmission and Distribution. Through our Electric Utilities, we own electric transmission and distribution systems composed of high voltage lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly operate an electric transmission system, referred to as the Common Use System, with Basin Electric Power Cooperative and Powder River Energy Corporation. Each participant in the Common Use System individually owns assets that are operated together for a single system. The Common Use System also provides transmission service to our Transmission Tie. South Dakota Electric owns 35% of the Transmission Tie. The Transmission Tie is further discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

At December 31, 2021, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission [(a)] (in Line Miles)	Distribution (in Line Miles)
Colorado Electric	Colorado	598	3,157
South Dakota Electric [(b)]	South Dakota, Wyoming	1,192	2,566
Wyoming Electric	Wyoming	59	1,327
		1,849	7,050

____

(a) Electric transmission line miles include voltages of 69 kV and above.
(b) South Dakota Electric transmission line miles include 43 miles within the Common Use System.

Material transmission services agreements are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Seasonal Variations of Business. Our Electric Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, cooling demand is often greater in the summer and heating demand in often greater in the winter.

Competition. We generally have limited competition for the retail generation and distribution of electricity in our service areas. Various legislative or regulatory restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have not had a material impact on our utilities. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated IPPs for the right to supply electric energy and capacity for Colorado Electric when resource plans require additional resources. Additionally, electrification initiatives in our service territories could increase demand for electricity and increase customer growth.

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 to foster competition within the wholesale electricity markets. Our non-regulated power generation businesses 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 IPPs in some regions. To date, these initiatives have not had a material impact on our non-regulated power generation businesses.

Our strategy for our mining business is to sell nearly all of our production to on-site generation facilities under long-term supply contracts. Historically, any off-site sales have been to consumers within close proximity to the WRDC mine. Rail transport market opportunities for WRDC are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC mine is served by only one railroad, resulting in less competitive transportation rates. 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 and availability considerations affect the overall demand for coal as a fuel.

Rates and Regulation. Our Electric Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate and the FERC for certain assets and transactions. These commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities and the creation of liens on property located in their states to secure bonds or other securities.

The following table provides regulatory information for each of our Electric Utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Regulatory Mechanisms	Percentage of Power Marketing Profit Shared with Customers
Colorado Electric [(a)]	CO	9.37%	7.43%	48%/52%	$539.6	1/2017	ECA, TCA, PCCA, EECR/DSM, RESA	90%
	CO	9.37%	6.02%	67%/33%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	N/A
South Dakota Electric	WY	9.90%	8.13%	47%/53%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TFA, EIA	70%
	FERC	10.80%	8.76%	43%/57%	$148.4 [(b)]	2/2009	FERC Transmission Tariff	N/A
Wyoming Electric [(a)]	WY	9.90%	7.98%	46%/54%	$376.8	10/2014	PCA, EECR/DSM, Rate Base Recovery on Acquisition Adjustment	N/A

(a) For both Colorado Electric and Wyoming Electric, transmission investments are recovered through retail rates rather than FERC Transmission Tariffs.
(b) Includes $131.3 million in 2021 rate base for the 2021 Projected Common Use System formula rate that is updated annually and $17.1 million in rate base for the Transmission Tie that is based on the approved stated rate from 2005.

The regulatory provisions for recovering the costs to supply electricity vary by state. We have cost adjustment mechanisms for our Electric Utilities that allow us to pass the prudently-incurred cost of fuel and purchased power to customers. These mechanisms allow the utility operating in that state to collect, or refund the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. In addition, some states allow for recovery of new capital investment placed in service between base rate reviews through approved rider tariffs. These tariffs allow the utility a return on the investment.

A summary of mechanisms we have in place are shown in the table below:

Electric Utility Jurisdiction	Cost Recovery Mechanisms						
	Environmental Cost	Energy Efficiency	Transmission Expense	Fuel Cost	Transmission Capital	Purchased Power	RESA
Colorado Electric		☑	☑	☑	☑	☑	☑
South Dakota Electric (SD) [(a)]	☑		☑	☑	☑	☑	
South Dakota Electric (WY) [(b)]		☑	☑	☑		☑	
South Dakota Electric (FERC) [(c)]					☑		
Wyoming Electric		☑	☑	☑		☑	

(a) South Dakota Electric's Environmental Cost (EIA) and Transmission Capital (TFA) tariffs were suspended for a six-year moratorium period effective July 1, 2017. On January 7, 2020, South Dakota Electric received approval from the SDPUC to extend the 6-year moratorium period by an additional 3 years whereby these recovery mechanisms will not be effective prior to July 1, 2026.
(b) South Dakota Electric has WPSC authorization to accumulate certain Energy Efficiency costs in a regulatory asset with determination of recovery to be made in the next rate review.
(c) South Dakota Electric has an approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric's open access transmission tariff.

Tariff Filings. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for tariff filings and additional information regarding current electric regulatory activity.

Operating Statistics. See a summary of key operating statistics in the Electric Utilities segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Gas Utilities

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities transport and distribute natural gas through our distribution network to approximately 1,094,000 customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as-available basis.

We also provide non-regulated services to our regulated customers. Black Hills Energy Services provides natural gas supply to approximately 52,400 retail distribution customers under the Choice Gas Program in Nebraska and Wyoming. Additionally, we provide services under the Service Guard Comfort Plan, Tech Services and HomeServe.

	As of December 31,		
Retail Customers	2021	2020	2019
Residential	853,908	844,999	831,351
Commercial	84,234	83,135	82,912
Industrial	2,158	2,235	2,208
Transportation	153,929	152,568	149,971
Total Natural Gas Retail Customers at End of Year	1,094,229	1,082,937	1,066,442

	As of December 31,		
Retail Customers	2021	2020	2019
Arkansas	180,216	178,281	174,447
Colorado	202,747	197,817	191,950
Iowa	161,905	160,952	159,641
Kansas	117,862	116,973	115,846
Nebraska	298,832	296,778	293,576
Wyoming	132,667	132,136	130,982
Total Natural Gas Retail Customers at End of Year	1,094,229	1,082,937	1,066,442

We procure natural gas for our distribution customers from a diverse mix of producers, processors and marketers and generally use hedging, physical fixed-price purchases and market-based price purchases to achieve dollar-cost averaging within our natural gas portfolio. The majority of our procured natural gas is transported in interstate pipelines under firm transportation service agreements.

In addition to company-owned natural gas storage assets in Arkansas, Colorado and Wyoming, we also contract with third-party transportation providers for natural gas storage service to provide gas supply during the winter heating season and to meet peak day customer demand for natural gas.

The following table summarizes certain information regarding our company-owned regulated underground gas storage facilities as of December 31, 2021:

State	Working Capacity (Mcf)	Cushion Gas (Mcf)	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas	9,273,700	12,318,040	21,591,740	196,000
Colorado	2,361,495	6,164,715	8,526,210	30,000
Wyoming	5,733,900	17,145,600	22,879,500	36,000
Total	17,369,095	35,628,355	52,997,450	262,000

The following table summarizes certain information regarding our system infrastructure as of December 31, 2021:

State	Intrastate Gas Transmission Pipelines (in line miles)	Gas Distribution Mains (in line miles)	Gas Distribution Service Lines (in line miles)
Arkansas	874	4,972	1,275
Colorado	693	6,990	2,303
Iowa	172	2,863	2,486
Kansas	330	2,980	1,374
Nebraska	1,311	8,443	2,773
Wyoming	1,352	3,532	1,653
Total	4,732	29,780	11,864

Seasonal Variations of Business. Our Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for natural gas is sensitive to seasonal heating and industrial load requirements, as well as market price. In particular, demand is often greater in the winter months for heating. Natural gas is used primarily for residential and commercial heating, and demand for this product can depend heavily upon weather throughout our service territories. As a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters. Demand for natural gas can also be impacted by summer temperatures and precipitation, which can affect demand for irrigation.

Competition. We generally have limited competition for the retail distribution of natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives are aimed at increasing competition. Additionally, electrification initiatives in our service territories could negatively impact demand for natural gas and decrease customer growth. To date, these initiatives have not had a material impact on our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a charge for transporting the gas through our distribution network.

Rates and Regulation. Our Gas Utilities are subject to the jurisdiction of the public utility commissions in the states where they operate. These commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities and the creation of liens on property located in their states to secure bonds or other securities.

Our Gas Utilities are authorized to use natural gas cost recovery mechanisms allowing rate adjustments reflecting changes in the wholesale cost of natural gas and recovery of all the costs prudently incurred in purchasing gas for customers. In addition to natural gas cost recovery mechanisms, other recovery mechanisms, which vary by utility, allow us to recover certain costs or earn a return on capital investments, such as energy efficiency plan costs and system safety and integrity investments.

The following table provides regulatory information for each of our natural gas utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Regulatory Mechanisms
Arkansas Gas [c]	AR	9.61%	6.82% [a]	51%/49%	$451.5 [b]	10/2018	GCA, Main Replacement Program, At-Risk Meter Relocation Program, Legislative or Regulatory Mandated Expenditures, EECR, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas [c]	CO	9.20%	6.56%	50%/50%	$303.2	1/2022	GCA, SSIR, EECR/DSM
RMNG	CO	9.90%	6.71%	53%/ 47%	$118.7	6/2018	SSIR, Liquids/Off-system/Market Center Services Revenue Sharing
Iowa Gas [c]	IA	9.60%	6.75%	50%/50%	$300.9	1/2022	GCA, EECR, System Safety and Maintenance Adjustment Rider, Gas Supply Optimization revenue sharing
Kansas Gas [c]	KS	Global Settlement	Global Settlement	Global Settlement	Global Settlement	1/2022	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment, Tax Adjustment Rider, Gas Supply Optimization revenue sharing
Nebraska Gas [d]	NE	9.50%	6.71%	50%/50%	$504.2	3/2021	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge, Choice Gas Program, SSIR, Bad Debt expense recovered through Choice Supplier Fee, Line Locate Surcharge
Wyoming Gas [d]	WY	9.40%	6.98%	50%/50%	$354.4	3/2020	GCA, EECR, Rate Base Recovery on Acquisition Adjustment, Wyoming Integrity Rider, Choice Gas Program

(a) Arkansas Gas return on rate base is adjusted to remove certain liabilities from rate review capital structure for comparison with other subsidiaries.
(b) Arkansas Gas rate base is adjusted to include certain liabilities for comparison with other subsidiaries.
(c) For additional information regarding recent rate review updates, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.
(d) The Choice Gas Program mechanisms are applicable to only a portion of Nebraska Gas and Wyoming Gas customers.

All of our Gas Utilities, except where the Choice Gas Program is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews. Some of the mechanisms we have in place include the following:

	Cost Recovery Mechanisms						
Gas Utility Jurisdiction	DSM/Energy Efficiency	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Gas Cost	Revenue Decoupling
Arkansas Gas	☑	☑		☑		☑	☑
Colorado Gas	☑	☑				☑	
RMNG [a]		☑					
Iowa Gas	☑	☑				☑	
Kansas Gas		☑	☑	☑	☑	☑	
Nebraska Gas		☑	☑			☑	
Wyoming Gas	☑	☑				☑	

(a) RMNG, which is an intrastate transmission pipeline that provides natural gas transmission and wholesale services in western Colorado, has an SSIR recovery mechanism. The other cost recovery mechanisms are not applicable to RMNG.

Tariff Filings. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current natural gas regulatory activity.

Operating statistics. See a summary of key operating statistics in the Gas Utilities segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Utility Regulation Characteristics

Federal Regulation

Energy Policy Act. The Energy Policy Act of 2005 included provisions to create an Electric Reliability Organization, which is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. FERC certified NERC as the Electric Reliability Organization and also issued an initial order approving many reliability standards that went into effect in 2007. Entities that violate standards can be subject to fines and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

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 Utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities entities 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, Electric Quarterly Reports are filed 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.

PUHCA 2005. PUHCA 2005 provides FERC authority with respect to the books and records of a utility holding company. As a utility holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and also a centralized service company subsidiary, BHSC, we are subject to FERC's authority under PUHCA 2005.

PUHCA 2005 reiterated the definition and benefits of EWG status. Under PUHCA 2005, an EWG is an entity or generator engaged, directly or indirectly through one or more affiliates, exclusively in the business of owning, operating or both owning and operating all or part of one or more eligible facilities and selling electric energy at wholesale. Though EWGs are public utilities within the definition set forth in the Federal Power Act and are subject to FERC regulation of rates and charges, they are exempt from other FERC requirements. Through its subsidiaries, Black Hills Corporation is affiliated with three EWGs, Wygen I, Pueblo Airport Generation (facilities #4-5) and Top of Iowa. Each of these three EWGs have been granted market-based rate authority.

Environmental Matters

In November 2020, we announced clean energy goals to reduce GHG emissions that are based on prudent and proven solutions while minimizing cost impacts to our customers. See more information in Key Elements of our Business Strategy within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

We are subject to significant state and federal environmental regulations that encourage the use of clean energy technologies and regulate emissions of GHGs. We have undertaken initiatives to meet current requirements and to prepare for anticipated future regulations, reduce GHG emissions, and respond to state renewable and energy efficiency goals. Compliance with future environmental regulations could result in substantial cost.

In July of 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for GHG reductions from coal-fired power plants. In a January 2021 decision, the U.S. Court of Appeals for the D. C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. That decision, if not successfully appealed or reconsidered, would allow the EPA to proceed with alternate regulation of coal-fired power plants, either reviving the Clean Power Plan or proposing additional regulation. Compliance could result in significant investment.

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 continually assess risk and develop mitigation strategies to manage and ensure compliance across the enterprise successfully and responsibly. For additional information on environmental matters, see Item 1A and Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Human Capital Resources

Overview

Black Hills Corporation is committed to supporting operational excellence by attracting, motivating, retaining and encouraging the development of a highly qualified and diverse employee team. Our employees' drive and dedication to their work, and their commitment to the safety of our customers and their fellow employees, allows Black Hills Corporation to successfully grow and manage our business year over year. The impacts of COVID-19 to our businesses and employees are discussed in the Recent Developments within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Our Team	As of December 31, 2021	As of December 31, 2020
Total employees	2,884	3,011
Women in executive leadership positions [(a)]	30%	31%
Gender diversity (women as a % of total employees)	26%	26%
Represented by a union	25%	25%
Military veterans	14%	16%
Ethnic diversity (non-white employees as a % of total)	12%	11%
	For the year ended December 31, 2021	For the year ended December 31, 2020
Number of external hires	214	299
External hires gender diversity (as a % of total external hires)	25%	29%
External hires ethnic diversity (as a % of total external hires)	20%	16%
Turnover rate [(b)]	11%	8%
Retirement rate	3%	3%

____
(a) Executive leadership positions are defined as positions with Vice President, Senior Vice President or Chief in their title.
(b) Includes voluntary and involuntary separations, but excludes internships.

Total Employees

	Number of Employees As of December 31, 2021
Electric Utilities	420
Gas Utilities	1,191
Corporate and Other	1,273
Total	2,884

At December 31, 2021, approximately 20% of our total employees and 22% of our Electric and Gas Utilities employees were eligible for retirement (age 55 with at least 5 years of service).

Collective Bargaining Agreements

At December 31, 2021, certain employees of our Electric Utilities and Gas Utilities were covered by the collective bargaining agreements as shown in the table below. We have not experienced any labor stoppages in decades.

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Colorado Electric	94	IBEW Local 667	April 15, 2023
South Dakota Electric	128	IBEW Local 1250	March 31, 2022
Wyoming Electric	25	IBEW Local 111	June 30, 2024
Total Electric Utilities	247		
Iowa Gas	132	IBEW Local 204	January 31, 2026
Kansas Gas	16	Communications Workers of America, AFL-CIO Local 6407	December 31, 2024
Nebraska Gas	92	IBEW Local 244	March 13, 2022
Nebraska Gas	140	CWA Local 7476	October 30, 2023
Wyoming Gas	15	IBEW Local 111	June 30, 2024
Wyoming Gas	78	CWA Local 7476	October 30, 2023
Total Gas Utilities	473		
Total	720		

Attraction

Continuous attraction of qualified team members is critical to our ability to serve our 1.3 million customers safely and efficiently. We actively recruit qualified candidates and continuously evaluate our interviewing and hiring practices to ensure equitable pay and processes. Our attraction efforts include the use of multiple nation-wide job boards, local college and high school outreach programs, a robust college internship program and participation in national and local job fairs. We have targeted diversity initiatives specific to recruiting groups, such as women, minorities and veterans, to fulfill our vision of continuing to build a thriving workforce, which is best able to support our communities, our customers and our shareholders.

Diversity & Inclusion

At Black Hills Corporation, we believe in the benefits of diversity, equity and inclusion. We believe that a diverse workforce will assist us in executing our strategic business plans, including our growth strategy. Workforce diversity trends, including diverse new hires, promotions and turnover, are monitored at regular intervals.

Development and Retention

Retaining and developing team members is critical to our continued success. Our retention efforts include competitive compensation programs, monitoring employee engagement, career development resources for all employees and internal training programs. Our compensation programs are designed to be strategically aligned, externally competitive, internally equitable, personally motivating, cost effective and legally compliant. We continuously monitor employee engagement through bi-annual engagement surveys and quarterly pulse surveys. Every leader is responsible for creating and implementing an action plan based on their team's engagement survey results. Our career development resources include management onboarding, leadership development programs, mentoring programs, individual development assessments and more. Internal training opportunities include corporate-wide trainings and specialized training opportunities for different job functions. Our Field Career Path Program (FCPP) promotes career growth through established standards of knowledge, skills, abilities and performance.

Employee Safety and Wellness

Safety is one of our company values, a top priority in all we do and deeply embedded in our culture. We are committed to consistently outperforming utility industry averages in key safety metrics. Meetings of three or more employees begin with a safety share, a practice which contributes to keeping safety top of mind. Since 2009, we have reduced workplace injuries by more than 75% and continue to see long-term, sustained improvements in our safety practices and performance.

	For the year ended December 31, 2021
Total Case Incident Rate (incidents per 200,000 hours worked)	1.06
Preventable Motor Vehicle Incident Rate (vehicle accidents per 1 million miles driven)	1.81
Proactive Safety and Wellness Participation Rate [(a)]	71%

(a) Measures the employee engagement rate in a fitness tracking system used for the Company's well-being program.

ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. Risks that may adversely affect our business operations, financial condition, results of operations or cash flows are described below. These risk factors, along with other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company.

STRATEGIC RISKS

Our continued success is dependent on execution of our strategic business plans including our growth strategy.

Our success depends, in significant part, on our ability to execute our strategic business plans, including our growth strategy. Our plans and strategy include building sustainable operations and supporting the Energy Transition; consistently outperforming utility industry averages in key safety metrics; modernizing utility infrastructure; transforming the customer experience; growing our electric and natural gas customer load; and pursuing operating efficiencies. Our current plans and strategy may be negatively impacted by disruptive forces and innovations in the marketplace, changing political, business or regulatory conditions and technology advancements.

In addition, we have significant capital investment programs planned for the next five years that are key to our strategic business plans. The successful execution of our capital investment program depends on, or could be affected by, a variety of factors that include, but are not limited to: weather conditions, effective management of projects, availability of qualified construction personnel including contractors, changes in commodity and other prices, availability and inflationary cost of materials, governmental approvals and permitting, regulatory cost recovery and return on investment.

An inability to successfully and timely adapt to changing conditions and execute our strategic plans could materially affect our financial operating results including earnings, cash flow and liquidity.

Customer growth and usage in our service territories may fluctuate with economic conditions, emerging technologies, political influences or responses to price increases.

Our financial operating results are impacted by energy demand in our service territories. Customer growth and usage may be impacted by a number of factors, including the voluntary reduction in consumption of electricity and natural gas by our customers in response to increases in prices and energy efficiency programs, electrification initiatives that could negatively impact the demand for natural gas, economic conditions impacting customers' disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us could decline. Such developments could affect the price of energy and delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Each of these factors could materially affect our financial operating results including earnings, cash flow and liquidity.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

We may be subject to future laws, regulations or actions associated with climate change, including those relating to fossil-fuel generation and GHG emissions, which could increase our operating costs or restrict our market opportunities.

We own and operate regulated and non-regulated electric power plants that burn fossil fuels (natural gas and coal) and a surface mine that extracts and sells coal. We also purchase, store and deliver natural gas to our customers. These business activities are subject to evolving public concern regarding fossil fuels, GHG emissions (such as carbon dioxide and methane) and their impact on the climate.

There is uncertainty surrounding climate regulation due to legal challenges to some current regulations and anticipated new federal and/or state climate legislation and regulation. New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or capacity reductions of coal-fired power generation facilities or conversion to natural gas, and potential increased production from our combined cycle natural gas-fired generating units. Additional rules and regulations associated with fossil fuels and GHG emissions could result in the impairment or retirement of some of our existing or future transmission, distribution, generation and natural gas storage facilities or our coal mine. Further, these rules could create the need to purchase or build clean-energy fuel sources to fulfill obligations to our customers. These actions could also result in increased operating costs which could adversely impact customers and our financial operating results including earnings, cash flow and liquidity. We cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, financial condition or cash flows.

Future GHG constraints designed to minimize emissions from natural gas could likewise result in increased costs and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas among fuel alternatives. Certain cities in our operational footprint are focused on electrification and are considering initiatives that may restrict the direct use of natural gas in homes and businesses. Any such initiatives and legislation could have a negative impact on our results of operations, financial condition and cash flows.

We may be subject to unfavorable or untimely federal and state regulatory outcomes.

Our regulated Electric and Gas Utilities are subject to cost-of-service/rate-of-return regulation and earnings oversight from federal and eight state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our customer rates are regulated based on an analysis of our costs and investments, as reviewed and approved in regulatory proceedings. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our various regulatory authorities will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will result in full or timely recovery of our costs with a reasonable return on invested capital. In addition, adverse rate decisions, including rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, could be influenced by competitive, economic, political, legislative, public perception and regulatory pressures and adversely impact results of operations, financial condition and cash flows.

Each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs, including incremental costs from Winter Storm Uri, or integrity capital investments) outside of a base rate review in order to stabilize customer rates and reduce regulatory lag. If regulators decide to discontinue these tariff-based recovery mechanisms, it could negatively impact results of operations, financial condition and cash flows.

Costs could significantly increase to achieve or maintain compliance with existing or future environmental laws, regulations or requirements.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions (i.e. SO_2, NO_x, volatile organic compounds, particulate matter and GHG), water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other government approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure or inability to comply with evolving environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

Our business segments may not be successful in recovering increased capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on our business segments' financial position, results of operations or cash flows, future environmental compliance costs could have a significant negative impact.

Legislative and regulatory requirements may result in compliance penalties.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Many agencies employ mandatory civil penalty structures for regulatory violations. The FERC, NERC, CFTC, EPA, OSHA, SEC, TSA and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which could have a material adverse effect on our financial operating results including earnings, cash flow and liquidity.

Municipal governments may seek to limit or deny our franchise privileges.

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. We regularly engage in negotiations on renewals of franchise agreements with our municipal governments. We have from time to time faced challenges or ballot initiatives on franchise renewals. To date, we have been successful in resolving or defending each of these challenges. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation. We also cannot quantify the impact that such action would have on the remainder of our business operations.

Changes in Federal tax law may significantly impact our business.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we operate. Similar to the TCJA, sweeping legislation or regulation could be enacted by any of these governmental authorities which may affect our tax burden. Changes may include numerous provisions that affect businesses, including changes to corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which a change in corporate tax rate will affect our utility customers and the time period over which that change will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

OPERATING RISKS

Our financial performance depends on the successful operation of electric generating facilities, electric and natural gas transmission and distribution systems, natural gas storage facilities and a coal mine.

The risks associated with managing these operations include:

- Inherent dangers. Electricity and natural gas can be dangerous to employees and the general public. Failures of or contact with power lines, natural gas pipelines or service facilities and equipment may result in fires, explosions, property damage and personal injuries, including death. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events may not be fully covered by our insurance;

- Weather, natural conditions and disasters including impacts from climate change. Severe weather events, such as snow and ice storms (e.g., Winter Storm Uri), fires, tornadoes, strong winds, significant thunderstorms, flooding and drought, could negatively impact operations, including our ability to provide energy safely, reliably and profitably and our ability to complete construction, expansion or refurbishment of facilities as planned. Climate change may intensify these events or increase the frequency of occurrence;

- Acts of sabotage, terrorism or other malicious attacks. Damage to our facilities due to deliberate acts could lead to outages or other adverse effects;

- Operating hazards. Operating hazards such as leaks, mechanical problems and accidents, including fires or explosions, could impact employee and public safety, reliability and customer confidence;

- Equipment and processes. Breakdown or failure of equipment or processes, unavailability or increased cost of equipment, and performance below expected levels of output or efficiency could negatively impact our results of operations;

- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and natural gas that we sell to our retail and wholesale customers. If transmission is interrupted physically, mechanically or with cyber means, our ability to sell or deliver utility services and satisfy our contractual obligations may be hindered;

- Natural gas supply for generation and distribution. Our regulated utilities and non-regulated entities purchase natural gas from a number of suppliers for our generating facilities and for distribution to our customers. Our results of operations could be negatively impacted by the lack of availability and cost of natural gas, and disruptions in the delivery of natural gas due to various factors, including but not limited to, transportation delays, labor relations, weather, sabotage, cyber-attacks and environmental regulations;

- Replacement power. The cost of supplying or securing replacement power during scheduled and unscheduled outages of generation facilities could negatively impact our results of operations;

- Governmental permits. The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals could negatively impact our ability to operate and our results of operations;

- Operational limitations. Operational limitations imposed by environmental and other regulatory requirements and contractual agreements, including those that restrict the timing of generation plant scheduled outages, could negatively impact our results of operations;

- Increased costs. Increased capital and operating costs to comply with increasingly stringent laws and regulations, unexpected engineering, environmental and geological problems, and unanticipated cost overruns could negatively impact our results of operations;

- Supply chain disruptions. We rely on various suppliers in our supply chain for the materials necessary to execute on our capital investment program. Our supply chain, material costs, and capital investment program may be negatively impacted by unanticipated price increases due to factors exacerbated by the COVID-19 pandemic, such as inflation, including wage inflation, or due to supply restrictions beyond our control or the control of our suppliers;

- Labor and labor relations. The cost of recruiting and retaining skilled technical labor or the unavailability of such resources could have a negative impact on our operations. There is competition and a tightening market for skilled employees. During the COVID-19 pandemic and subsequent recovery, there is a national trend of increased employee turnover. Our ability to transition and replace our retirement-eligible utility employees is a risk; at December 31, 2021, approximately 22% of our Electric Utilities and Gas Utilities employees were eligible for retirement. Our ability to avoid or minimize supply interruptions, work stoppages and labor disputes is also a risk with approximately 25% of our employees are represented by unions; and

- Public opposition. Opposition by members of public or special-interest groups could negatively impact our ability to operate our businesses.

The ongoing operation of our business involves the risks described above, in addition to risks associated with threats to our overall business model, such as electrification initiatives. Any of these risks could cause us to experience negative financial results and damage to our reputation and public confidence. These risks could cause us to incur significant costs or be unable to deliver energy and/or operate below expected capacity levels, which in turn could reduce revenues or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under contracts, warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

Cyberattacks, terrorism, or other malicious acts targeting our key technology systems could disrupt our operations, or lead to a loss or misuse of confidential and proprietary information.

To effectively operate our business, we rely upon a sophisticated electronic control system, information and operation technology systems and network infrastructure to generate, distribute and deliver energy, and collect and retain sensitive information including personal information about our customers and employees. Cyberattacks, terrorism or other malicious acts targeting electronic control systems could result in a full or partial disruption of our electric and/or natural gas operations. Attacks targeting other key technology systems, including our third-party vendors' information systems, could further add to a full or partial disruption of our operations. Any disruption of these operations could result in a loss of service to customers and associated revenues, as well as significant expense to repair damages and remedy security breaches. In addition, any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others. We maintain cyber risk insurance to mitigate a portion, but not all, or these risks and losses.

In May and July 2021, the TSA issued security directives that included several new cybersecurity requirements for critical pipeline owners and operators. Among these requirements is the implementation of specific mitigation measures to protect against ransomware attacks and other known threats to information and operational technology systems; development and implementation of a cybersecurity contingency and recovery plan; and performance of a cybersecurity architecture design review. We are currently implementing several of these directives and evaluating the potential effect of several others on our operations and facilities, as well as the potential cost of implementation, and will continue to monitor for any clarifications or amendments to these directives.

We have instituted security measures and safeguards to protect our operational systems and information technology assets, including certain safeguards required by FERC. Despite our implementation of security measures and safeguards, all of our technology systems may still be vulnerable to disability, failures or unauthorized access.

Weather conditions, including the impacts of climate change, may cause fluctuation in customer usage.

Our utility businesses are seasonal businesses and weather conditions and patterns can have a material impact on our operating performance. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, respectively. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters, therefore, could have an adverse effect on our financial operating results, including earnings, cash flow and liquidity.

FINANCIAL RISKS

A sub-investment grade credit rating could impact our ability to access capital markets.

Our senior unsecured debt rating is Baa2 (Stable outlook) by Moody's; BBB+ (Stable outlook) by S&P; and BBB+ (Stable outlook) by Fitch. Reduction of our investment grade credit ratings could impair our ability to refinance or repay our existing debt and complete new financings on reasonable terms, if at all. A credit rating downgrade, particularly to sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities, potentially significantly increasing our cost of capital and other associated operating costs which may not be recoverable through existing regulatory rate structures and contracts with customers.

Our use of derivative financial instruments as hedges against commodity prices and financial market risks could result in material financial losses.

We use various financial and physical derivatives, including futures, forwards, options and swaps, to manage commodity price and interest rate risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP may not consistently match up with the gains or losses on the commodities being hedged. For Black Hills Energy Services under the Choice Gas Program, and in certain instances within our regulated Utilities where unrealized and realized gains and losses from derivative instruments are not approved for regulatory accounting treatment, fluctuating commodity prices may cause fluctuations in reported financial results due to mark-to-market accounting treatment.

To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Additionally, our exchange-traded futures contracts are subject to futures margin posting requirements. To the extent we are unable to meet these requirements, this could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. Further, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries.

As a holding company, our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital, equity or debt service funds.

There is no assurance as to the amount, if any, of future dividends to the holding company because these subsidiaries depend on future earnings, capital requirements and financial conditions to fund such dividends. See "Liquidity and Capital Resources" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and Note 8 of the Notes to Consolidated Financial Statements of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

We may be unable to obtain financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt, pay dividends and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in commodity or electricity prices and general economic and market conditions.

In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

National and regional economic conditions may cause increased counterparty credit risk, late payments and uncollectible accounts.

A future recession or pandemic, if one occurs, may lead to an increase in late payments or non-payment from retail residential, commercial and industrial utility customers, as well as from our non-utility customers. If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

We may be unable to obtain insurance coverage, and the coverage we currently have may not apply or may be insufficient to cover a significant loss.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting the insurance industry and the financial condition of insurers. Additionally, insurance providers could deny coverage or decline to extend coverage under the same or similar terms that are presently available to us. A loss for which we are not adequately insured could materially affect our financial results. The coverage we currently have in place may not apply to a particular loss, or it may not be sufficient to cover all liabilities to which the Company may be subject, including liability and losses associated with climate change, wildfire, natural gas and storage field explosions, cyber-security breaches, environmental hazards and natural disasters.

Market performance or changes in key valuation assumptions could require us to make significant unplanned contributions to our pension plan and other postretirement benefit plans.

Assumptions related to interest rates, expected return on investments, mortality and other key actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to our pension and other postretirement benefit plans. An adverse change to key assumptions associated with our defined benefit retirement plans may require significant unplanned contributions to the plans which could adversely affect our financial operating results including earnings, cash flow and liquidity.

Costs associated with our healthcare plans and other benefits could increase significantly.

The costs of providing healthcare benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to healthcare plans for our employees and former employees, will continue to rise. Significant regulatory developments have required, and likely will continue to require, changes to our current employee benefit plans and supporting administrative processes. Our electric and natural gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates, we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, however, there is no assurance that the utility commissions will allow recovery of these increased costs. The rising employee benefit costs, or inadequate recovery of such costs, may adversely affect our financial operating results including earnings, cash flow, or liquidity.

PANDEMIC RISK

The ongoing COVID-19 pandemic, including its variants, or any other pandemic and the associated impact on business and economic conditions could negatively affect our business operations, results of operations, financial condition and cash flows.

The scale and scope of the COVID-19 outbreak, the resulting pandemic or any other future pandemic, and the associated impact on the economy and financial markets could adversely affect the Company’s business, results of operations and financial condition. As a provider of essential services, the Company has an obligation to provide electric and natural gas services to our customers. The Company remains focused on protecting the health of our customers, employees and the communities in which we operate while assuring the continuity of our business operations.

Although the impact of the COVID-19 pandemic and its variants to our 2021 results of operation was not significant, we cannot ultimately predict whether it will have a material impact on our future liquidity, financial condition or results of operations. We also cannot predict the impact of COVID-19 on the health of our employees, our supply chain or our ability to mitigate higher costs associated with managing through the COVID-19 pandemic.

As recovery from the COVID-19 pandemic continues, additional uncertainties have emerged, including the impacts of:
- vaccine mandates and testing requirements on our workforce;
- inflation increasing prices of commodities and materials, outside services, employee costs and interest rates;
- supply chain disruptions on the availability and cost of materials; and
- labor shortages and increased turnover on costs of retaining and attracting employees.

The situation remains fluid and it is difficult to predict with certainty the potential impact of the COVID-19 pandemic, or any other future pandemic, on our financial operating results including earnings, cash flows and liquidity.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

See Item 1 for a description of our principal business properties.

In addition to the properties disclosed in the Item 1, we own or lease several facilities throughout our service territories including a corporate headquarters building and various office, service center, storage, shop and warehouse space. 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.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the “Legal Proceedings” sub-caption within Item 8, Note 3, “Commitments, Contingencies and Guarantees”, of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act is included in Exhibit 95 of this Annual Report.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Linden R. Evans, age 59, 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. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and Associate Counsel from 2001 to 2003. Mr. Evans has 20 years of experience with the Company.

Brian G. Iverson, age 59, has been Senior Vice President, General Counsel and Chief Compliance Officer since August 26, 2019. He served as Senior Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary from February 1, 2019 to August 26, 2019, Senior Vice President, General Counsel and Chief Compliance Officer from 2016 to February 2019, Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to 2016, Vice President and Treasurer from 2011 to 2014, Vice President - Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 18 years of experience with the Company.

Erik D. Keller, age 58, joined the Company as Senior Vice President and Chief Information Officer on July 27, 2020. Prior to joining the company, he was an Information Technology consultant to Ontic Inc., a global provider of parts and services for legacy aerospace platforms, from January 2020 to July 2020, and Chief Information Officer for BBA Aviation, a global aviation support and aftermarket services provider, from February 2012 to January 2020.

Richard W. Kinzley, age 56, has been Senior Vice President and Chief Financial Officer since 2015. He served as Vice President - Corporate Controller from 2013 to 2014, Vice President - Strategic Planning and Development from 2008 to 2013, and as Director of Corporate Development from 2000 to 2008. Mr. Kinzley has 22 years of experience with the Company.

Jennifer C. Landis, age 47, has been Senior Vice President - Chief Human Resources Officer since February 1, 2017. She served as Vice President of Human Resources from April 2016 through January 2017, Director of Corporate Human Resources and Talent Management from 2013 to April 2016, and Director of Organization Development from 2008 to 2013. Ms. Landis has 20 years of experience with the Company.

Stuart A. Wevik, age 60, has been Senior Vice President - Utility Operations since August 26, 2019. He served as Group Vice President - Electric Utilities from 2016 to August 2019, Vice President - Utility Operations from 2008 to 2016, Vice President - Operations from 2004 to 2008 and Vice President and General Manager from 2003 to 2004. Mr. Wevik has 36 years of experience with the Company. Mr. Wevik intends to retire on June 1, 2022.

Table of Contents

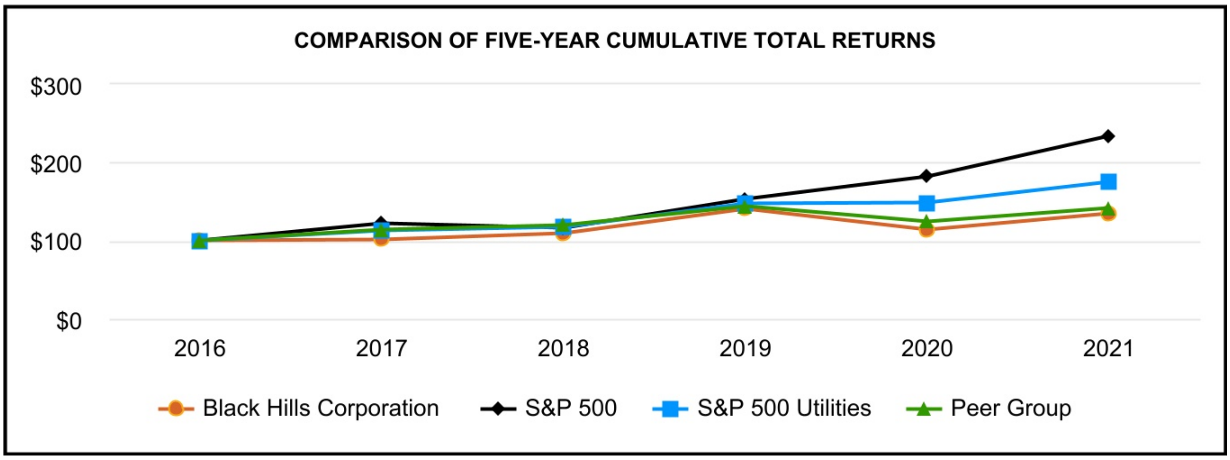
PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of January 31, 2022, we had 3,475 common shareholders of record and 60,937 beneficial owners, representing all 50 states, the District of Columbia and 7 foreign countries.

COMPARATIVE STOCK PERFORMANCE

The following performance graph compares the cumulative total stockholder return from Black Hills Corporation common stock, as compared with the S&P 500 Index, S&P 500 Utilities index, and our performance peer group for the past five years. The graph assumes an initial investment of $100 on December 31, 2016, and assumes all dividends were reinvested. The stockholder return shown below for the five-year historical period may not be indicative of future performance. The information in this "Comparative Stock Performance" section shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission or subject to Regulation 14A or 14C, or to the liabilities of Section 18 of the Securities Exchange Act of 1934.



	Years ended December 31,					
	2016	2017	2018	2019	2020	2021
Black Hills Corporation	$ 100.00	$ 100.77	$ 108.81	$ 139.91	$ 113.21	$ 134.59
S&P 500	100.00	121.83	116.49	153.17	181.35	233.41
S&P 500 Utilities	100.00	112.11	116.71	147.46	148.18	174.36
Performance Peer Group [(a)]	100.00	113.59	119.17	143.70	123.74	140.78

(a) Performance Peer Group represents the list of 20 utility and energy industry companies used in our 2021 Proxy Statement which was filed with the SEC on March 18, 2021.

DIVIDENDS

For information concerning dividends, our dividend policy and factors that may limit our ability to pay dividends, see “Key Elements of our Business Strategy” and “Liquidity and Capital Resources” under Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-K.

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2021.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

See Item 12 in this Annual Report on Form 10-K for information regarding Securities Authorized for Issuance Under Equity Compensation Plans.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table contains monthly information about our acquisitions of equity securities for the three months ended December 31, 2021:

Period	Total Number of Shares Purchased [(a)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
October 1, 2021 - October 31, 2021	1	$ 63.15	—	—
November 1, 2021 - November 30, 2021	777	66.10	—	—
December 1, 2021 - December 31, 2021	8,680	68.40	—	—
Total	9,458	$ 68.21	—	—

(a) Shares were acquired under the share withholding provisions of the Omnibus Incentive Plan for payment of taxes associated with the vesting of various equity compensation plans.

ITEM 6. (RESERVED)

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Executive Summary

We are a customer-focused energy solutions provider that invests in our communities' safety, sustainability and growth with a mission of *Improving Life with Energy* and a vision to be the *Energy Partner of Choice*. The Company's core mission— and our primary focus — is to provide safe, reliable and cost-effective electric and natural gas service to 1.3 million utility customers in over 800 communities in eight states, including Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming.

We conduct our business operations through two operating segments: Electric Utilities and Gas Utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other. The Company conducts its utility operations under the name Black Hills Energy predominantly in rural areas of the Rocky Mountains and Midwestern states. The Company considers itself a domestic electric and natural gas utility company.

The Company has provided energy and served customers for 138 years, since the 1883 gold rush days in Deadwood, South Dakota. Throughout our history, the common thread that unites the past to the present is our commitment to serve our customers and communities. By being responsive and service focused, we can help our customers and communities thrive while meeting rapidly changing customer expectations.

An important component of our strategy involves sustainable operations and supporting the Energy Transition. How we operate our company for the social good has never been more important. We are committed to cleaner energy and a low carbon future, integrating the Energy Transition and more renewable energy into our overall strategy and decision making. For this important work, we are *Ready* to serve. In addition, we are committed to a more sustainable future by better managing our impacts to the planet, whether that is water usage, recycling, biodiversity, or other important measures, and remaining focused on our human capital through diversity and inclusion.

Our emphasis is on consistently outperforming utility industry averages in key safety metrics; modernizing utility infrastructure; transforming the customer experience; growing our electric and natural gas customer load; and pursuing operating efficiencies. These areas of focus will present the company with significant investment needs as we harden our infrastructure systems, meet customer growth and fulfill customer expectations for cleaner energy services. It will also allow us to better understand our customer and community needs while providing more intuitive and cost-effective solutions.

Key Elements of our Business Strategy

Modernize and operate utility infrastructure to provide customers with safe, reliable, cost-effective electric and natural gas service. Our utilities own and operate large electric and natural gas infrastructure systems with a geographic footprint that spans nearly 1,600 miles. Our Electric Utilities own and operate 1,481.5 MW of generation capacity and 8,900 miles of transmission and distribution lines and our Gas Utilities own and operate 47,000 miles of natural gas transmission and distribution pipelines.

A key strategic focus is to modernize and harden our utility infrastructure to meet customers' and communities' varied energy needs, ensure the continued delivery of safe, reliable and cost-effective energy and reduce GHG emissions intensity. In addition, we invest in the expansion, capacity and integrity of our systems to meet customer growth.

We rigorously comply with all applicable federal, state and local regulations and strive to consistently meet industry best practice standards. A key component of our modernization effort is the development of programs by our Electric and Gas Utilities to systematically and proactively replace aging infrastructure on a system-wide basis.

To meet our electric customers' continued expectations of high levels of reliability, a key strength of the Company, our Electric Utilities utilize an integrity program to ensure the timely repair and replacement of aging infrastructure. In alignment with this program, in November 2021, Wyoming Electric announced its Ready Wyoming electric transmission expansion initiative. The 285-mile, multi-phase transmission expansion project will serve the growing needs of customers enhancing the resiliency of its overall electric system and expanding access to power markets and renewable energy resources. The project will enable Wyoming Electric to maintain top-quartile reliability and support further economic growth in the Cheyenne area. Wyoming Electric plans to file an application with the WPSC seeking approval for the project in the first quarter of 2022. Following approval, construction would commence in early 2023.

Our Gas Utilities utilize a programmatic approach to system-wide pipeline replacement, particularly in high consequence areas. Under the programmatic approach, obsolete, at-risk and vintage materials are replaced in a proactive and systematic time frame. We have removed all cast- and wrought-iron from our natural gas transmission and distribution systems and continue to replace aging infrastructure through programs that prioritize safety and reliability for our customers. Our Gas Utilities are authorized to use system safety, integrity and replacement cost recovery mechanisms that provide for customer rate adjustments, between rate reviews, which allow timely recovery of costs incurred in repairing and replacing the gas delivery systems with a return on the investment.

As of December 31, 2021, we estimate our five-year capital investment to be approximately $3.2 billion, with most of that investment targeted toward upgrading existing utility infrastructure supporting customer and community growth needs, and complying with safety requirements. Our actual 2021 and forecasted capital expenditures for the next five years from 2022 through 2026 are as follows (in millions):

	Actual [(a)]	**Forecasted**				
Capital Expenditures By Segment :	2021	2022	2023	2024	2025	2026
(in millions)						
Electric Utilities	$ 286	$ 239	$ 205	$ 285	$ 231	$ 155
Gas Utilities	383	363	383	386	349	346
Corporate and Other	11	9	12	13	13	13
Incremental projects [(b)]	—	—	—	—	60	140
Total	$ 680	$ 611	$ 600	$ 684	$ 653	$ 654

(a) Includes accruals for property, plant and equipment as disclosed as supplemental cash flow information in the Consolidated Statements of Cash Flows in the Consolidated Financial Statements in this Annual Report on Form 10-K.
(b) These represent projects that are being evaluated by our segments for timing, cost and other factors.

Efficiently plan, construct and operate power generation facilities to serve our Electric Utilities. We best serve customers and communities when generation is vertically integrated into our Electric Utilities. This business model remains a core strength and strategy today as we invest in and operate efficient power generation resources to supply cost-effective electricity to our customers. These generation assets can be rate-based or non-regulated assets within our Electric Utilities segment. However, we believe that generation assets that are rate-based provide long-term benefits to customers. In the fourth quarter of 2021, we revised our operating segments to align with our vertically integrated business model for our Electric Utilities. Our power generation and mining businesses, which were previously presented as separate operating segments, are now part of our vertically integrated Electric Utilities segment.

Our power production strategy focuses on low-cost construction and efficient operation of our generating facilities. Our low power production costs result from a variety of factors including low fuel costs (operations located near energy hubs), efficiency in converting fuel into energy and low per unit operating and maintenance costs. In addition, we operate our plants with high levels of Availability as compared to industry benchmarks.

Rate Base Generation: We continue to believe that customers are best served when the power generation facilities are owned and rate-based by our Electric Utilities. Rate-based generation assets offer several advantages for customers and shareholders, including:

- When generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run; especially when compared to power otherwise purchased from the open market through wholesale contracts or PPAs that are periodically re-priced to reflect current and varying market conditions;

- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;

- The lower-risk profile of rate-based generation assets contributes to stronger credit ratings which, in turn, can benefit both customers and investors by lowering the cost of capital; and

- Investors are provided a long-term and stable return on their investment.

Integrated Generation: Our Electric Utilities segment also contains a power generation business that owns non-regulated generating facilities that are contracted through long-term power purchase agreements with our electric utilities. Our power generation business has an experienced staff with significant expertise in planning, building and operating power plants. This team also provides shared services to our Electric Utilities' generation facilities, resulting in efficient management of all of the company's generation assets. This business competitively bids for energy and capacity through requests for proposals by our Electric Utilities for energy resources necessary to serve customers. This business can bid competitively due to construction expertise, fuel supply advantages and by co-locating new plants at our existing Electric Utilities' energy complexes, reducing infrastructure and operating costs. All power plants within this business, except Top of Iowa, are contracted to our Electric Utilities under long-term contracts and are located at our utility-generating complexes, including Busch Ranch, Pueblo Airport Generation, and the Gillette, Wyoming energy complex, and are physically integrated into our Electric Utilities' operations.

Generation Fuel Supply: Our generating facilities are strategically located close to energy hubs that help reduce fuel supply costs. Our Colorado and Wyoming gas-fired generating facilities are located close to major natural gas energy hubs that provide trading liquidity and transparent pricing. Due to their location in the resource rich areas of Colorado and Wyoming, natural gas supply to fuel our gas-fired generation can be sourced at competitive prices. Our only coal-fired power plants, all located at the Gillette energy complex in northeastern Wyoming, are supplied by our adjacent coal mine. We operate and own majority interests in four of the five power plants and own 20% of the fifth power plant. The small coal mine provides approximately 3.5 million tons of low-sulfur coal directly to these power plants via a conveyor belt system, minimizing transportation costs. On average, the fuel can be delivered to the adjacent power plants at less than $1.00 per MMBtu, providing very cost competitive fuel to our power plants when compared to alternatives. Nearly all the mine's production is sold to these on-site generation facilities under long-term supply contracts. Approximately one-half of our production is sold under cost-plus contracts with affiliates. A small portion of the mine's production is sold to off-site industrial customers and delivered by truck.

Supporting the Energy Transition by proactively integrating alternative and renewable energy into our utility energy supply while mitigating customer rate impacts. In November 2020, we announced clean energy goals to reduce GHG emissions intensity for our Electric Utilities of 40% by 2030 and 70% by 2040 and achieve GHG reductions of 50% by 2035 for our Gas Utilities. Our goals are based on existing technology and computed from 2005 baseline levels of GHG emissions intensity for our electric operations and natural gas distribution system. Since 2005, we have reduced GHG emissions intensity from our Gas Utilities by more than 33% and achieved a 30% reduction from our Electric Utilities (an additional 5% reduction since announcing our goal in 2020 for our Electric Utilities). Additionally, our Electric Utilities have reduced nitrogen oxide and sulfur dioxide emissions by more than 75% since 2005. Our electric utility in Colorado has achieved a nearly 50% reduction in GHG emissions since 2005 and is on track to reach the State of Colorado's 80% carbon reduction goal by 2030. Our goals are based on prudent and proven solutions to reduce our emissions while minimizing cost impacts to our customers. This keeps our customers at the forefront of our decision-making, which is central to our values.

More of our customers, particularly our larger customers, are demanding cleaner sources of energy to meet their sustainability goals. In addition, there is more interest from consumers, regulators and legislators to increase the use of renewable and other alternative energy sources. To support this interest:

- We created the Renewable Ready program for South Dakota and Wyoming customers. In support of this program, we created and received approvals for new, voluntary renewable energy tariffs to serve certain commercial, industrial and governmental customer requests for renewable energy resources. To meet the renewable energy commitments under the new tariffs, on November 30, 2020, we completed construction and placed into service the Corriedale wind project, a 52.5 MW wind energy project near Cheyenne, Wyoming.

- In June 2021, South Dakota Electric and Wyoming Electric submitted an IRP to the SDPUC and WPSC. The IRP outlines a range of options for the two electric utilities over a 20-year planning horizon to meet long-term forecasted energy needs while strengthening reliability and resiliency of the grid. The analysis focused on the least-cost resource needs to best meet customers' future peak energy needs while maintaining system flexibility and achieving the Company's generation emissions reduction goals. The IRP's preferred options for the near-term planning period through 2026 propose the addition of 100 MW of renewable generation, the conversion of Neil Simpson II to natural gas in 2025 and consideration of up to 20 MW of battery storage.

Many states have enacted, and others are considering, mandatory renewable energy standards, requiring utilities to meet certain thresholds of renewable energy generation. In addition, some states have either enacted or are considering legislation setting GHG emission reduction targets. Federal legislation for renewable energy standards and GHG emission reductions has been considered and may be implemented in the future. Mandates for the use of renewable energy or the reduction of GHG emissions will likely drive the need for significant investment in our Electric Utilities and Gas Utilities segments. These mandates will also likely increase prices for electricity and/or natural gas for our utility customers. As a regulated utility we are responsible for providing safe, reliable and cost-effective sources of energy to our customers. Accordingly, we employ a customer-focused strategy for complying with standards and regulations that balances our customers' rate concerns with environmental considerations and administrative and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers.

Explore opportunities as an energy solutions provider. Another strategic initiative is to grow our business through creative energy solutions with new customers and partnerships. We see value creation by recruiting new customers and expanding existing partnerships with data centers, crypto miners and other blockchain opportunities; exploring energy markets such as RTOs; and expanding our transmission capabilities. As an example, we have supported enabling legislation in Wyoming for the growing blockchain and digital currency businesses while implementing our own Blockchain Interruptible Service Tariff to serve these customers. We are also re-focusing on our product and services offerings to our natural gas customers.

Additionally, we are pursuing two important initiatives in the form of sustainable energy solutions for electric vehicles and renewable natural gas. These two programs support our near-term sustainable strategy and contribute to the achievement of our aspirational greenhouse gas emissions reduction goals.

- <u>Electric Vehicles (EV)</u>: We expect EV market share to increase over the next one to three years, commensurate with a significant uptick in vehicle range and product offerings and marked decrease in EV purchase prices. In addition to future load growth opportunities, we will investigate behind-the-meter solutions for customers. In January 2022, the CPUC approved a transportation electrification plan for Colorado Electric including the implementation of EV and charger rebates and EV rates.

- <u>Renewable Natural Gas (RNG)</u>: Our teams are developing RNG/carbon offset offerings for our retail customers, evaluating multiple RNG investment opportunities and exploring value generation with our natural gas storage assets. We also continue to expand our RNG interconnections, with several projects actively injecting RNG into our natural gas system.

Execute disciplined capital allocation and explore small strategic opportunities. We are planning a disciplined capital investment program of approximately $600 million annually over the next two years to improve our cash flows and reduce our debt to total capitalization ratio. By carefully managing capital, we plan to continue to strengthen our balance sheet and enhance our liquidity. With this goal in mind, we will continue to evaluate smaller scale acquisitions of private utility infrastructure systems and small municipal systems that can be easily incorporated into our existing utility systems.

Deliver a competitive total return to investors and maintain an investment grade credit rating. We are proud of our track record of annual dividend increases for shareholders. 2021 represented our 51st consecutive year of increasing dividends. In January 2022, our Board of Directors declared a quarterly dividend of $0.595 per share, equivalent to an annual dividend of $2.38 per share. We intend to continue our record of annual dividend increases with a targeted dividend payout ratio of 50% to 60%.

We require access to the capital markets to fund our planned capital investments or acquire strategic assets that support prudent and earnings-accretive business growth. We have demonstrated our ability to cost-effectively access the debt and equity markets, while maintaining our investment-grade issuer credit rating.

Recent Developments

Winter Storm Uri

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

On February 24, 2021, we entered into a nine-month, $800 million unsecured term loan to provide additional liquidity and to meet our cash needs related to the incremental fuel, purchased power and natural gas costs from Winter Storm Uri. Proceeds from the August 26, 2021 debt transaction were used to repay amounts outstanding under this term loan. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

During the second quarter, our Utilities submitted cost recovery applications with the utility commissions in our state jurisdictions to recover incremental costs associated with Winter Storm Uri. To date, several of our Utilities have received interim or final Commission Orders and have begun recovering costs from customers. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information on our regulatory activity.

COVID-19 Pandemic

For the year ended December 31, 2021, we did not experience significant impacts to our financial results, liquidity or operational activities due to COVID-19. We continue to monitor loads, customers' ability to pay, the potential for supply chain disruption or inflation that may impact our capital and maintenance project plans, the availability of third-party resources to execute our business plans and the capital markets to ensure we have the liquidity necessary to support our financial needs. State Orders lifting temporarily suspended disconnections have been issued in all of our jurisdictions.

As we look forward, our operating results could be affected by COVID-19 as discussed in detail in our Risk Factors.

Business Segment Highlights and Corporate Activity

Electric Utilities

- On January 26, 2022, Colorado Electric agreed to join SPP's Western Energy Imbalance Service Market. Colorado Electric, PRPA, and the Colorado subsidiary of Xcel Energy Inc. will join the market in April 2023 and will continue to study long-term solutions for joining or developing an organized wholesale market. The expansion allows the utilities to participate in a real-time market to dispatch energy at lower costs.

- On January 5, 2022, South Dakota Electric and Wyoming Electric set new winter peak loads. This is the fourth new winter peak for Wyoming Electric since 2015. Wyoming Electric's new winter peak load of 253 MW surpasses the previous peak of 247 MW set in December 2019. South Dakota Electric's new winter peak of 327 MW surpasses the previous winter peak of 326 MW set in February 2021.

- In November 2021, Wyoming Electric announced its *Ready Wyoming* electric transmission expansion initiative. See Key Elements of our Business Strategy above for further information.

- On October 5, 2021, our Electric Utilities and several other utilities in the western United States formed the Western Markets Exploratory Group to research the potential for an organized wholesale market in the western interconnect, including expanding transmission systems and other grid-related services. The group plans to identify market solutions that can help achieve carbon reduction goals while supporting reliable, cost-effective services for customers.

- On September 19, 2021, Wygen I experienced an unplanned outage that continued until mid-December 2021. For the year ended December 31, 2021, the outage had an $11 million negative impact to Operating income. We are currently assessing insurance recovery opportunities.

- On August 24, 2021, Wyoming Electric issued a request for proposals under its Blockchain Interruptible Service tariff. We have narrowed the bidder's list and selected finalists for contract negotiations.

- On July 28, 2021, Wyoming Electric set a new all-time and summer peak load of 274 MW, exceeding the previous peak of 271 MW set in July 2020.

- On July 27, 2021, South Dakota Electric set a new all-time and summer peak load of 397 MW, exceeding the previous peak of 378 MW set in August 2020.

- On June 30, 2021, South Dakota Electric and Wyoming Electric submitted an IRP to the SDPUC and WPSC. See Key Elements of our Business Strategy above for further information.

- On February 19, 2021, Colorado Electric entered into a PPA with TC Colorado Solar, LLC (TC Solar) to purchase up to 200 MW of renewable energy upon construction of a new solar facility, to be owned by TC Solar. On January 31, 2022, TC Solar provided termination notice of the PPA to Colorado Electric. Colorado Electric has disputed TC Solar's right to termination and pursuant to the agreement, has initiated discussions with TC Solar.

Gas Utilities

- See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for recent regulatory activity for our Gas Utilities in Arkansas, Colorado, Iowa, Kansas and Nebraska.

Corporate and Other

- On August 26, 2021, we completed a public debt offering which consisted of $600 million, 1.037% 3-year senior unsecured notes due August 23, 2024. The proceeds from the offering were used to repay amounts outstanding under our term loan entered into on February 24, 2021. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

- On July 19, 2021, we amended and restated our corporate Revolving Credit Facility. See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

Results of Operations

Our discussion and analysis for the year ended December 31, 2021 compared to 2020 as well as discussion and analysis of the results of operations for the year ended December 31, 2020 compared to 2019, is included herein. For further discussion and analysis that remains unchanged for the year ended December 31, 2020 compared to 2019, please refer to Item 7 of Part II, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2020, which was filed with the SEC on February 26, 2021.

In the fourth quarter of 2021, we integrated our power generation and mining businesses within the Electric Utilities segment. The alignment is consistent with the current way our CODM evaluates the performance of the business and makes decisions related to the allocation of resources. Comparative periods presented reflect this change. See further segment information in Note 16 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Segment information does not include intercompany eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated. Minor differences in amounts may result due to rounding.

Consolidated Summary and Overview

	For the Years Ended December 31,		
	2021	2020	2019
	(in thousands, except per share amounts)		
Operating income (loss):			
Electric Utilities	$ 202,676	$ 210,974	$ 217,677
Gas Utilities	211,157	215,889	189,971
Corporate and Other	(4,404)	1,440	(1,606)
Operating Income	409,429	428,303	406,042
Interest expense, net	(152,404)	(143,470)	(137,659)
Impairment of investment	—	(6,859)	(19,741)
Other income (expense), net	1,404	(2,293)	(5,740)
Income tax (expense)	(7,169)	(32,918)	(29,580)
Net income	251,260	242,763	213,322
Net income attributable to non-controlling interest	(14,516)	(15,155)	(14,012)
Net income available for common stock	$ 236,744	$ 227,608	$ 199,310
Total earnings per share of common stock, Diluted	$ 3.74	$ 3.65	$ 3.28

2021 Compared to 2020

The variance to the prior year included the following:

- Electric Utilities' operating income decreased $8.3 million primarily due to Colorado Electric's TCJA-related bill credits to customers (which is offset by reduced tax expense), unfavorable impacts from an unplanned outage at Wygen I and higher depreciation as a result of additional plant placed in service, partially offset by increased power marketing and wholesale revenues, increased rider revenues, increased commercial and industrial demand, a prior year expense related to the early retirement of certain non-regulated generation assets, residential customer growth and increased usage, and prior year COVID-19 impacts;
- Gas Utilities' operating income decreased $4.7 million primarily due to Winter Storm Uri costs incurred by Black Hills Energy Services, lower heating demand from milder weather (primarily in the fourth quarter of 2021), Nebraska Gas TCJA-related bill credits to customers and higher operating expenses partially offset by new rates and customer growth;
- Corporate and Other expenses increased $5.8 million primarily due to higher employee costs driven by a prior year favorable true-up;
- Interest expense increased $8.9 million primarily due to higher debt balances partially offset by lower rates;
- A prior year $6.9 million pre-tax non-cash impairment in 2020 of our investment in equity securities of a privately held oil and gas company;
- Other income increased $3.7 million primarily due to lower non-service pension costs driven by a lower discount rate, lower costs for our non-qualified benefit plans which were driven by market performance and recognition of death benefits from Company-owned life insurance; and

- Income tax expense decreased $26 million primarily due to lower pre-tax income and a lower effective tax rate driven primarily by tax benefits from Colorado Electric and Nebraska Gas TCJA-related bill credits (which is offset by reduced revenue), flow-through tax benefits related to repairs and gain deferral and increased tax benefits from federal production tax credits associated with new wind assets.

2020 Compared to 2019

The variance to the prior year included the following:

- COVID-19 related impacts to consolidated results included $3.6 million of lower Electric and Gas Utility margin driven primarily by lower volumes and waived customer late payment fees, $2.6 million of costs due to sequestration of essential employees and $3.3 million of additional bad debt expense which were partially offset by $3.8 million of lower travel, training, and outside services related expenses;
- Electric Utilities' operating income decreased $6.7 million due to higher depreciation and amortization expense as a result of additional plant placed in service including new wind assets, expense from the early retirement of certain non-regulated assets, lower commercial and industrial demand and COVID-19 impacts partially offset by increased revenue from our non-regulated power generation and mining businesses, benefits from the release of TCJA revenue reserves and increased rider revenues;
- Gas Utilities' operating income increased $26 million primarily due to new customer rates in Wyoming and Nebraska and increased rider revenues, customer growth, mark-to-market gains on non-utility natural gas commodity contracts and a 2019 amortization of excess deferred income taxes partially offset by higher depreciation and amortization expense as a result of additional plant placed in service, COVID-19 impacts and unfavorable weather;
- Corporate and Other expenses decreased $3.0 million primarily due to an unallocated favorable true-up of employee costs;
- A $6.9 million pre-tax non-cash impairment in 2020 of our investment in equity securities of a privately held oil and gas company compared to a similar $20 million impairment in 2019;
- Interest expense increased $5.8 million primarily due to higher debt balances partially offset by lower rates;
- Other expense decreased $3.4 million due to the 2019 expensing of $5.4 million of development costs related to projects we no longer intend to construct partially offset by increased pension non-service costs in 2020; and
- Income tax expense increased $3.3 million primarily due to higher pre-tax income partially offset by a lower effective tax rate.

Segment Operating Results

A discussion of operating results from our business segments follows.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, Electric and Gas Utility margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Electric and Gas Utility margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of operation and maintenance expenses, depreciation and amortization expenses, and property and production taxes from the measure.

Electric Utility margin is calculated as operating revenue less cost of fuel and purchased power. Gas Utility margin is calculated as operating revenue less cost of natural gas sold. Our Electric and Gas Utility margin is impacted by the fluctuations in power and natural gas purchases and other fuel supply costs. However, while these fluctuating costs impact Electric and Gas Utility margin as a percentage of revenue, they only impact total Electric and Gas Utility margin if the costs cannot be passed through to our customers.

Our Electric and Gas Utility margin measure may not be comparable to other companies' Electric and Gas Utility margin measures. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in thousands):

	2021	2020	2021 vs 2020 Variance	2019	2020 vs 2019 Variance
Revenue:					
Electric - regulated	$ 800,747	$ 699,712	$ 101,035	$ 698,807	$ 905
Other - non-regulated	41,511	39,145	2,366	40,548	(1,403)
Total revenue	842,258	738,857	103,401	739,355	(498)
Fuel and Purchased Power:					
Electric - regulated	244,504	136,374	108,130	143,668	(7,294)
Other - non-regulated	3,514	2,198	1,316	2,305	(107)
Total fuel and purchased power	248,018	138,572	109,446	145,973	(7,401)
Electric Utility margin (non-GAAP)	594,240	600,285	(6,045)	593,382	6,903
Operations and maintenance	260,036	265,679	(5,643)	259,167	6,512
Depreciation and amortization	131,528	123,632	7,896	116,538	7,094
Total operating expenses	391,564	389,311	2,253	375,705	13,606
Operating income	$ 202,676	$ 210,974	$ (8,298)	$ 217,677	$ (6,703)

2021 Compared to 2020

Electric Utility margin decreased over the prior year as a result of:

	(in millions)
TCJA-related bill credits [(a)]	$ (10.2)
Wygen I unplanned outage	(8.5)
Prior year release of TCJA revenue reserves	(2.2)
Weather	(1.2)
Winter Storm Uri impacts [(b)]	(0.4)
Power marketing and wholesale	5.9
Residential customer growth and increased usage per customer	5.1
Rider recovery	4.2
Prior year COVID-19 impacts	1.8
Other	(0.5)
Total decrease in Electric Utility margin	$ (6.0)

____

(a) In February and April 2021, Colorado Electric delivered TCJA-related bill credits to its customers. These bill credits were offset by a reduction in income tax expense and resulted in a minimal impact to Net income.
(b) As a result of Winter Storm Uri, our Electric Utilities incurred $2.1 million of incremental fuel costs that are not recoverable through our fuel cost recovery mechanisms which were mostly offset by $1.7 million of increased Electric Utility margin realized under Black Hills Wyoming's Economy Energy PSA.

Operations and maintenance expense decreased primarily due to a $3.1 million prior year expense related to the early retirement of certain non-regulated generation assets, $2.7 million of lower overburden, production taxes and other operating expenses on decreased mining volumes, $2.0 million of prior year COVID-19 expenses and $1.7 million of decreased bad debt expense associated with lower expected credit losses, partially offset by $2.7 million of increased expenses related to planned and unplanned outages at our generation facilities and $1.0 million of increased operating expenses from new wind assets.

Depreciation and amortization increased primarily due to higher asset base driven by prior and current year capital expenditures.

2020 Compared to 2019

Electric Utility margin increased in 2020 over 2019 as a result of:

		(in millions)
Integrated Generation [(a)]	$	3.3
Rider recovery		2.3
Release of TCJA revenue reserves [(b)]		2.2
Transmission services		1.4
Residential customer growth		0.9
Lower commercial and industrial demand		(2.7)
COVID-19 impacts [(c)]		(1.8)
Weather		(0.3)
Other		1.6
Total increase in Electric Utility margin	$	6.9

(a) Primarily driven by revenue from Busch Ranch II, which was placed in service in November 2019.
(b) In July 2020, regulatory proceedings resolved the last of the Company's open dockets seeking approval of its TCJA plans. As a result, the Company reversed certain TCJA-related liabilities, which resulted in an increase to Electric Utility margin of $2.2 million. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.
(c) The impacts to Electric Utility margin from COVID-19 were primarily driven by reduced commercial volumes and waived customer late payment fees partially offset by higher residential usage.

Operations and maintenance expense increased primarily due to a $3.1 million expense related to the early retirement of certain non-regulated assets, $2.0 million of higher maintenance expense from new wind assets and $2.0 million of unfavorable net impacts from COVID-19 which included $2.6 million of expenses related to the sequestration of essential employees and $0.8 million of additional bad debt expense which were partially offset by $1.4 million of lower travel, training and outside services related expenses. Additionally, lower employee costs of $1.9 million were partially offset by $1.0 million of higher property taxes due to a higher asset base driven by capital expenditures.

Depreciation and amortization increased primarily due to higher asset base driven by capital expenditures.

Operating Statistics

	Revenue (in thousands)			Quantities Sold (MWh)		
For the year ended December 31,	2021	2020	2019	2021	2020	2019
Residential	$ 244,589	$ 221,530	$ 216,108	1,494,028	1,477,515	1,440,551
Commercial	275,998	239,166	246,704	2,075,690	1,974,043	2,055,253
Industrial	149,040	131,154	131,831	1,751,344	1,794,795	1,787,412
Municipal	19,092	16,860	17,206	162,903	158,222	157,298
Subtotal Retail Revenue - Electric	688,719	608,710	611,849	5,483,965	5,404,575	5,440,514
Contract Wholesale	16,128	17,847	19,078	574,137	492,637	368,360
Off-system/Power Marketing Wholesale	41,682	15,511	17,886	638,923	437,288	507,042
Other [(a)]	54,218	57,644	49,994	—	—	—
Total Regulated	800,747	699,712	698,807	6,697,025	6,334,500	6,315,916
Non-Regulated [(b)]	41,511	39,145	40,548	269,558	258,399	238,415
Total Revenue and Quantities Sold	842,258	738,857	739,355	6,966,583	6,592,899	6,554,331
Other Uses, Losses or Generation, net [(c)]				475,280	406,422	393,573
Total Energy				7,441,863	6,999,321	6,947,904

(a) Primarily related to transmission revenues from the Common Use System.
(b) Includes Integrated Generation and non-regulated services to our retail customers under the Service Guard Comfort Plan and Tech Services.
(c) Includes company uses and line losses.

Table of Contents

For the year ended December 31,	Electric Revenue (in thousands) 2021	2020	2019	Quantities Sold (MWh) 2021	2020	2019
Colorado Electric	$ 302,896	$ 252,094	$ 246,197	2,574,016	2,243,034	2,046,728
South Dakota Electric	319,362	280,431	288,120	2,389,407	2,363,776	2,519,448
Wyoming Electric	180,413	169,179	167,345	1,733,602	1,727,690	1,749,740
Integrated Generation	39,587	37,153	37,693	269,558	258,399	238,415
Total Revenue and Quantities Sold	$ 842,258	$ 738,857	$ 739,355	6,966,583	6,592,899	6,554,331

Quantities Generated and Purchased by Fuel Type (MWh)	For the year ended December 31, 2021	2020	2019
Generated:			
Coal	2,546,926	2,817,846	2,783,147
Natural Gas and Oil	1,817,133	1,753,568	1,535,999
Wind	842,616	614,236	406,295
Total Generated	5,206,675	5,185,650	4,725,441
Purchased:			
Coal, Natural Gas, Oil and Other Market Purchases	1,866,382	1,478,536	2,019,359
Wind	368,806	335,135	203,104
Total Purchased	2,235,188	1,813,671	2,222,463
Total Generated and Purchased	7,441,863	6,999,321	6,947,904

Quantities Generated and Purchased (MWh)	For the year ended December 31, 2021	2020	2019
Generated:			
Colorado Electric	412,127	265,552	443,770
South Dakota Electric	1,980,660	1,901,009	1,768,456
Wyoming Electric	883,596	851,522	852,803
Integrated Generation	1,842,377	2,085,042	1,660,412
Total Generated	5,118,760	5,103,125	4,725,441
Purchased:			
Colorado Electric	1,027,728	714,139	741,666
South Dakota Electric	563,603	489,457	896,901
Wyoming Electric	643,857	610,075	509,697
Integrated Generation	87,915	82,525	74,199
Total Purchased	2,323,103	1,896,196	2,222,463
Total Generated and Purchased	7,441,863	6,999,321	6,947,904

Degree Days	For the year ended December 31, 2021		2020		2019	
	Actual	Variance from Normal	Actual	Variance from Normal	Actual	Variance from Normal
Heating Degree Days:						
Colorado Electric	5,023	(11)%	5,103	(9)%	5,453	(3)%
South Dakota Electric	6,819	(5)%	6,910	(3)%	8,284	16%
Wyoming Electric	6,702	(6)%	6,771	(5)%	7,406	1%
Combined [a]	5,974	(7)%	6,056	(6)%	6,813	5%
Cooling Degree Days:						
Colorado Electric	1,245	39%	1,384	54%	1,226	37%
South Dakota Electric	827	30%	682	7%	404	(36)%
Wyoming Electric	604	74%	594	71%	462	33%
Combined [a]	973	40%	985	41%	791	14%

(a) Degree days are calculated based on a weighted average of total customers by state.

Contracted generating facilities Availability by fuel type[a]	For the year ended December 31, 2021	2020	2019
Coal [b]	86.7%	94.3%	92.4%
Natural gas and diesel oil [c]	95.5%	84.6%	90.5%
Wind	95.8%	95.1%	89.5%
Total availability	93.2%	89.2%	90.9%
Wind Capacity Factor	34.0%	31.8%	30.9%

(a) Availability and Wind Capacity Factor are calculated using a weighted average based on capacity of our generating fleet.
(b) 2021 included planned outages at Neil Simpson II, Wygen II, and Wygen III and unplanned outages at Wygen I, Neil Simpson II and Wyodak Plant.
(c) 2020 included a planned outage at Cheyenne Prairie and unplanned outages at Pueblo Airport Generation and Lange CT. 2019 included planned outages at Neil Simpson CT and Lange CT.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in thousands):

	2021	2020	2021 vs 2020 Variance	2019	2020 vs 2019 Variance
Revenue:					
Natural gas - regulated	$ 1,051,610	$ 900,637	$ 150,973	$ 932,111	$ (31,474)
Other - non-regulated services	73,255	74,033	(778)	77,919	(3,886)
Total revenue	1,124,865	974,670	150,195	1,010,030	(35,360)
Cost of natural gas sold:					
Natural gas - regulated	480,293	347,611	132,682	406,643	(59,032)
Other - non-regulated services	14,445	7,034	7,411	19,255	(12,221)
Total cost of natural gas sold	494,738	354,645	140,093	425,898	(71,253)
Gas Utility margin (non-GAAP)	630,127	620,025	10,102	584,132	35,893
Operations and maintenance	314,810	303,577	11,233	301,844	1,733
Depreciation and amortization	104,160	100,559	3,601	92,317	8,242
Total operating expenses	418,970	404,136	14,834	394,161	9,975
Operating income	$ 211,157	$ 215,889	$ (4,732)	$ 189,971	$ 25,918

2021 Compared to 2020

Gas Utility margin increased over the prior year as a result of:

	(in millions)
New rates	$ 20.5
Carrying costs on Winter Storm Uri regulatory asset [(a)]	4.0
Increased transport and transmission	2.2
Prior year COVID-19 impacts	1.8
Mark-to-market on non-utility natural gas commodity contracts	0.9
Black Hills Energy Services Winter Storm Uri costs [(b)]	(8.2)
Weather	(6.8)
TCJA-related bill credits [(c)]	(2.9)
Other	(1.4)
Total increase in Gas Utility margin	$ 10.1

(a) In certain jurisdictions, we have Commission approval to recover carrying costs on Winter Storm Uri regulatory assets which offset increased interest expense.
(b) Black Hills Energy Services offers fixed contract pricing for non-regulated gas supply services to our regulated natural gas customers. The increased cost of natural gas sold during Winter Storm Uri is not recoverable through a regulatory mechanism.
(c) In June 2021, Nebraska Gas delivered TCJA-related bill credits to its customers. These bill credits were offset by a reduction in income tax expense and resulted in a minimal impact to Net income.

Operations and maintenance expense increased primarily due to $9.6 million of higher employee costs, $3.3 million of higher property taxes due to a higher asset base driven by prior and current year capital expenditures and $2.0 million of higher outside services expenses. The increase in expense was partially offset by $4.4 million of decreased bad debt expense associated with lower expected credit losses.

Depreciation and amortization increased primarily due to a higher asset base driven by prior and current year capital expenditures partially offset by lower depreciation rates approved in the Nebraska Gas and Colorado Gas rate reviews.

2020 Compared to 2019

Gas Utility margin increased in 2020 over 2019 as a result of:

		(in millions)
New rates	$	25.4
Customer growth - distribution		5.6
Mark-to-market on non-utility natural gas commodity contracts		3.3
Amortization of excess deferred income taxes in 2019		2.6
Weather		(1.8)
COVID-19 impacts [(a)]		(1.8)
Other		2.6
Total increase in Gas Utility margin	$	35.9

(a) The impacts to Gas Utility margin from COVID-19 were primarily driven by reduced volumes from certain transport customers and waived customer late payment fees.

Operations and maintenance expense increased primarily due to higher property taxes due to a higher asset base driven by capital expenditures. Lower employee costs were mostly offset by various other 2020 expenses. COVID-19 impacts to operations and maintenance expense included $2.5 million of additional bad debt expense which was partially offset by $2.4 million of lower travel, training, and outside services related expenses.

Depreciation and amortization increased primarily due to a higher asset base driven by capital expenditures.

Operating Statistics

	Revenue (in thousands)			Quantities Sold and Transported (Dth)		
	For the year ended December 31,			For the year ended December 31,		
	2021	2020	2019	2021	2020	2019
Residential	$ 613,475	$ 527,518	$ 551,701	60,080,805	61,962,171	66,956,080
Commercial	242,115	193,017	212,229	29,091,657	28,784,319	32,241,441
Industrial	33,368	24,014	24,832	6,260,235	6,881,354	6,548,023
Other	3,816	582	(1,361)	—	—	—
Total Distribution	892,774	745,131	787,401	95,432,697	97,627,844	105,745,544
Transportation and Transmission	158,836	155,506	144,710	154,570,280	149,062,476	153,101,264
Total Regulated	1,051,610	900,637	932,111	250,002,977	246,690,320	258,846,808
Non-regulated Services [(a)]	73,255	74,033	77,919	—	—	—
Total Revenue and Quantities Sold	$ 1,124,865	$ 974,670	$ 1,010,030	250,002,977	246,690,320	258,846,808

(a) Includes Black Hills Energy Services and non-regulated services under the Service Guard Comfort Plan, Tech Services and HomeServe.

Table of Contents

	Revenue (in thousands)			Quantities Sold and Transported (Dth)		
	For the year ended December 31,			For the year ended December 31,		
	2021	2020	2019	2021	2020	2019
Arkansas	$ 218,497	$ 184,849	$ 185,201	31,478,303	28,572,621	30,496,243
Colorado	208,019	186,085	199,369	32,247,042	32,077,083	33,908,529
Iowa	171,673	137,982	151,619	38,022,801	36,824,548	41,795,729
Kansas	121,603	101,118	105,906	34,475,799	33,732,897	32,650,854
Nebraska	273,361	246,381	255,622	81,035,572	80,202,783	81,481,192
Wyoming	131,712	118,255	112,313	32,743,460	35,280,388	38,514,261
Total Revenue and Quantities Sold	$ 1,124,865	$ 974,670	$ 1,010,030	250,002,977	246,690,320	258,846,808

	For the year ended December 31,					
	2021		2020		2019	
Heating Degree Days	Actual	Variance From Normal	Actual	Variance From Normal	Actual	Variance From Normal
Arkansas [(a)]	3,565	(12)%	3,442	(15)%	3,897	(4)%
Colorado	5,866	(11)%	6,068	(8)%	6,672	1%
Iowa	6,239	(8)%	6,504	(4)%	7,200	6%
Kansas [(a)]	4,508	(8)%	4,648	(5)%	5,190	6%
Nebraska	5,599	(9)%	5,853	(5)%	6,578	7%
Wyoming	7,074	(7)%	7,289	(4)%	8,010	7%
Combined [(b)]	5,948	(8)%	6,038	(6)%	6,840	5%

(a) Arkansas and Kansas have weather normalization mechanisms that mitigate the weather impact on Gas Utility margins.
(b) Heating degree days are calculated based on a weighted average of total customers by state excluding Kansas due to its weather normalization mechanism. Arkansas Gas is partially excluded based on the weather normalization mechanism in effect from November through April.

Corporate and Other

Corporate and Other operating results for the years ended December 31 were as follows (in thousands):

(in thousands)	2021	2020	2021 vs 2020 Variance	2019	2020 vs 2019 Variance
Operating income (loss)	$ (4,404)	$ 1,440	$ (5,844)	$ (1,606)	$ 3,046

2021 Compared to 2020

The variance in Operating income (loss) was primarily due to a prior year favorable true-up of employee costs which was allocated to our subsidiaries in the current year. This allocation was offset in our business segments and had no impact to consolidated results.

2020 Compared to 2019

The variance in Operating income (loss) was primarily due to a 2020 unallocated favorable true-up of employee costs.

Consolidated Interest Expense, Impairment of Investment, Other Income (Expense) and Income Tax Benefit (Expense)

(in thousands)	2021	2020	2021 vs 2020 Variance	2019	2020 vs 2019 Variance
Interest expense, net	$ (152,404)	$ (143,470)	$ (8,934)	$ (137,659)	$ (5,811)
Impairment of investment	—	(6,859)	6,859	(19,741)	12,882
Other income (expense), net	1,404	(2,293)	3,697	(5,740)	3,447
Income tax benefit (expense)	(7,169)	(32,918)	25,749	(29,580)	(3,338)

2021 Compared to 2020

Interest expense, net

The increase in Interest expense, net was due to higher debt balances driven by the August 2021 senior unsecured notes and February 2021 term loan, partially offset by lower interest rates.

Impairment of investment

In the prior year, we recorded a pre-tax non-cash write-down of $6.9 million in our investment in equity securities of a privately held oil and gas company. The impairment was triggered by continued adverse changes in future natural gas prices and liquidity concerns at the privately held oil and gas company.

Other income (expense), net

The variance in Other income (expense), net was primarily due to lower non-service pension costs driven by a lower discount rate, lower costs for our non-qualified benefit plans which were driven by market performance and recognition of death benefits from Company-owned life insurance.

Income tax benefit (expense)

For the year ended December 31, 2021, the effective tax rate was 2.8% compared to 11.9% in 2020. The lower effective tax rate is primarily due to $10 million of increased tax benefits from Colorado Electric and Nebraska Gas TCJA-related bill credits to customers (which is offset by reduced revenue), $6.6 million of increased flow-through tax benefits related to repairs and gain deferral, $4.6 million of increased tax benefits from federal production tax credits associated with new wind assets, $2.9 million of increased tax benefits from amortization of excess deferred income taxes and $2.6 million from various statutory rate changes. These current year tax benefits were greater than prior year tax benefits from one-time research and development tax credits and the reversal of accrued excess deferred income taxes as part of resolving the last of the Company's open dockets seeking approval of its TCJA plans. See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.

2020 Compared to 2019

Interest expense, net

The increase in Interest expense, net was driven by higher debt balances partially offset by lower interest rates.

Impairment of investment

In 2020, we recorded a pre-tax non-cash write-down of $6.9 million in our investment in equity securities of a privately held oil and gas company, compared to a $20 million write-down in 2019. The impairments in both years were triggered by continued adverse natural gas prices and liquidity concerns at the privately held oil and gas company.

Other income (expense), net

The variance in Other income (expense), net was primarily due to the 2019 expensing of $5.4 million of development costs related to projects we no longer intend to construct which was partially offset by higher 2020 non-service defined benefit plan costs primarily driven by lower discount rates.

Income tax benefit (expense)

For the year ended December 31, 2020, the effective tax rate was 11.9% compared to 12.2% in 2019. The lower effective tax rate is primarily due to increased tax benefits from federal production tax credits associated with new wind assets and one-time research and development tax credits partially offset by a 2019 tax benefit from a federal tax loss carry-back claim including interest. See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.

Liquidity and Capital Resources

OVERVIEW

Our company requires significant cash to support and grow our businesses. Our primary sources of cash are generated from our operating activities, five-year Revolving Credit Facility, CP Program, ATM and ability to access the public and private capital markets through debt and equity securities offerings when necessary. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate.

We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption, during periods of high natural gas prices, and during the construction season which typically peaks in spring and summer.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, regulatory liabilities, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

In response to Winter Storm Uri, we took steps to maintain adequate liquidity to operate our businesses and fund our capital investment program as discussed in the Recent Developments section above.

The following table provides an informational summary of our financial position as of December 31 (dollars in thousands):

Financial Position Summary	2021	2020
Cash and cash equivalents	$ 8,921	$ 6,356
Restricted cash and equivalents	$ 4,889	$ 4,383
Notes payable	$ 420,180	$ 234,040
Current maturities of long-term debt	$ —	$ 8,436
Long-term debt [(a)]	$ 4,126,923	$ 3,528,100
Stockholders' equity	$ 2,787,094	$ 2,561,385
Ratios		
Long-term debt ratio	60 %	58 %
Total debt ratio	62 %	60 %

(a) Carrying value of long-term debt is net of deferred financing costs.

CASH FLOW ACTIVITIES

The following table summarizes our cash flows for the years ended December 31 (in thousands):

	2021	2020	2019
Cash provided by (used in)			
Operating activities	$ (64,565)	$ 541,863	$ 505,513
Investing activities	$ (664,230)	$ (761,664)	$ (816,210)
Financing activities	$ 731,866	$ 216,882	$ 300,210

2021 Compared to 2020

Operating Activities:

Net cash used in operating activities was $606 million higher than in 2020. The variance to the prior year was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $21 million lower than prior year driven primarily by negative impacts from the unplanned outage at Wygen I, lower Electric and Gas Utility margin from Winter Storm Uri and unfavorable weather, higher operating expenses and higher interest expenses;

- Net outflows from changes in certain operating assets and liabilities were $593 million higher than prior year, primarily attributable to:

    - Cash outflows increased by approximately $508 million primarily as a result of changes in our regulatory assets and liabilities primarily driven by incremental fuel, purchased power and natural gas costs due to Winter Storm Uri;

    - Cash inflows decreased by approximately $71 million primarily as a result of changes in accounts receivable and other current assets driven by decreased collections of accounts receivable and increased purchases of natural gas in storage;

    - Cash inflows decreased by approximately $14 million as a result of changes in accounts payable and other current liabilities driven by payment timing related to payroll taxes;

- Cash outflows decreased by $13 million due to pension contributions made in the prior year; and

- Cash inflows decreased $4.5 million for other operating activities.

Investing Activities:

Net cash used in investing activities was $97 million lower than in 2020. This variance to the prior year was primarily attributable to:

- Capital expenditures of approximately $677 million in 2021 compared to $767 million in 2020. Lower current year expenditures are driven by lower programmatic safety, reliability and integrity spending at our Gas Utilities segments and the prior year Corriedale wind project at our Electric Utilities segment; and

- Cash inflows increased $7.5 million for other investing activities primarily driven by the sales of transmission assets and facilities, none of which were individually significant.

Financing Activities:

Net cash provided by financing activities was $515 million higher than in 2020. This variance to the prior year was primarily attributable to:

- Cash inflows increased $502 million due to long and short-term borrowings in excess of repayments;

- Cash inflows increased $20 million due to higher issuances of common stock;

- Cash outflows increased $10 million due to increased dividends paid on common stock; and

- Cash outflows decreased by $3.0 million for other financing activities.

CAPITAL RESOURCES

Short-term Debt

Revolving Credit Facility and CP Program

We have a $750 million Revolving Credit Facility that matures on July 19, 2026 with two one-year extension options (subject to consent from lenders). This facility includes an accordion feature that allows us to increase total commitments up to $1.0 billion with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment. We also 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 Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

The Revolving Credit Facility contains cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to 1) make timely payments of debt obligations; or 2) triggered other default provisions under any debt agreement totaling, in the aggregate principal amount of $50 million or more that permit the acceleration of debt maturities or mandatory debt prepayment.

Our Revolving Credit Facility and CP Program had the following borrowings, outstanding letters of credit, and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Short-term borrowings at December 31, 2021	Letters of Credit [a] at December 31, 2021	Available Capacity at December 31, 2021
Revolving Credit Facility and CP Program	July 19, 2026	$ 750	$ 420	$ 27	$ 303

(a) Letters of credit are off-balance sheet commitments that reduce the borrowing capacity available on our corporate Revolving Credit. For more information on these letters of credit, see Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

The weighted average interest rate on short-term borrowings at December 31, 2021 was 0.30%. Short-term borrowing activity for the year ended December 31, 2021 was:

	(dollars in millions)
Maximum amount outstanding (based on daily outstanding balances)	$ 440
Average amount outstanding (based on daily outstanding balances)	$ 258
Weighted average interest rate	0.22 %

See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more information on our Revolving Credit Facility and CP Program.

Term Loan

See Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more information related to our term loan.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utilities and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may, at their option, borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates. While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

Long-term Debt

Our Long-term debt and associated interest payments due by year are shown below (in thousands). For more information on our long-term debt, see Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

	Payments Due by Period						
	2022	2023	2024	2025	2026	Thereafter	Total
Principal payments on Long-term debt including current maturities [a]	$ —	$ 525,000	$ 600,000	$ —	$ 300,000	$ 2,735,000	$ 4,160,000
Interest payments on Long-term debt [a]	147,720	147,772	125,460	119,238	113,313	1,095,879	1,749,382

(a) Long-term debt amounts do not include deferred financing costs or discounts or premiums on debt. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2021.

Covenant Requirements

The Revolving Credit Facility and Wyoming Electric's financing agreements contain covenant requirements. We were in compliance with these covenants as of December 31, 2021. See additional information in Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Equity

Shelf Registration

We have a shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. The shelf registration expires in August 2023. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2021, we had approximately 65 million shares of common stock outstanding and no shares of preferred stock outstanding.

ATM

Our ATM allows us to sell shares of our common stock with an aggregate value of up to $400 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2020. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. During the twelve months ended December 31, 2021, we issued a total of 1,812,197 shares of common stock under the ATM for $119 million, net of $1.1 million in issuance costs.

For additional information regarding equity, see Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Future Financing Plans

We will continue to assess debt and equity needs to support our capital investment plans and other key strategic objectives. In 2022, we expect to fund our capital plan and strategic objectives by using cash generated from operating activities, our Revolving Credit Facility and CP Program, and issuing $100 million to $120 million of common stock under the ATM.

CREDIT RATINGS

Financing for operational needs and capital expenditure requirements, not satisfied by operating cash flows, depends upon the cost and availability of external funds through both short and long-term financing. In order to operate and grow our business, we need to consistently maintain the ability to raise capital on favorable terms. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the Company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. We note that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2021:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB+	Stable
Moody's [(b)]	Baa2	Stable
Fitch [(c)]	BBB+	Stable

(a) On October 20, 2021, S&P reported BBB+ rating and maintained a Stable outlook.
(b) On December 20, 2021, Moody's reported Baa2 rating and maintained a Stable outlook.
(c) On September 17, 2021, Fitch reported BBB+ rating and maintained a Stable outlook.

Certain fees and interest rates under our Revolving Credit Facility are based on our credit ratings at all three rating agencies. If all of our ratings are at the same level, or if two of our ratings are the same level and one differs, these fees and interest rates will be based on the ratings that are at the same level. If all of our ratings are at different levels, these fees and interest rates will be based on the middle level. Currently, our Fitch and S&P ratings are at the same level, and our Moody's rating is one level below. Therefore, if Fitch or S&P downgrades our senior unsecured debt, we will be required to pay higher fees and interest rates under our Revolving Credit Facility.

The following table represents the credit ratings of South Dakota Electric at December 31, 2021:

Rating Agency	Senior Secured Rating
S&P [(a)]	A
Fitch [(b)]	A

(a) On July 1, 2021, S&P reported A rating.
(b) On September 17, 2021, Fitch reported A rating.

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs, or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings.

CAPITAL REQUIREMENTS

Capital Expenditures

Capital expenditures are a substantial portion of our cash requirements each year and we continue to forecast a robust capital expenditure program during the next five years. See above in Key Elements of our Business Strategy for forecasted capital expenditure requirements. A significant portion of our capital expenditures are for safety, reliability and integrity of our system and is included in utility rate base and eligible for recovery from our utility customers with regulatory approval. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate.

Our capital expenditures for the three years ended December 31 were as follows (in thousands):

	2021	2020	2019
Capital Expenditures By Segment [(a)] :			
Electric Utilities	$ 285,770	$ 288,683	$ 316,687
Gas Utilities	383,320	449,209	512,366
Corporate and Other	10,500	17,500	20,702
Total capital expenditures	$ 679,590	$ 755,392	$ 849,755

(a) Includes accruals for property, plant and equipment as disclosed as supplemental cash flow information in the Consolidated Statements of Cash Flows in the Consolidated Financial Statements in this Annual Report on Form 10-K.

Repayments of Indebtedness

For information relating to repayments of our short- and long-term debt and associated interest payments, see the Capital Resources section above and Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Unconditional Purchase Obligations

We have unconditional purchase obligations which include the energy and capacity costs associated with our PPAs, transmission services agreements, and natural gas capacity, transportation and storage agreements. Additionally, our Gas Utilities have commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. For additional information. see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Defined Benefit Pension Plan

We have one defined benefit pension plan, the Black Hills Retirement Plan (Pension Plan). The unfunded status of the Pension Plan is defined as the amount the projected benefit obligation exceeds the plan assets. The unfunded status of the plan is $20 million as of December 31, 2021, compared to $40 million as of December 31, 2020. While we do not have required contributions, we expect to make $3.9 million in contributions to our Pension Plan in 2022. See further information in Note 13 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Common Stock Dividends

Future cash dividends, if any, will be dependent on our results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated and approved by our Board of Directors.

Additionally, there are certain statutory limitations that could affect future cash dividends paid. Federal law places limits on the ability of public utilities within a holding company structure to declare dividends. Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants. See additional information in Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

On January 26, 2022, our Board of Directors declared a quarterly dividend of $0.595 per share, equivalent to an annual dividend rate of $2.38 per share. The table below provides our dividends paid (in thousands), dividend payout ratio and dividends paid per share for the three years ended December 31:

	2021	2020	2019
Common Stock Dividends Paid	$ 145,023	$ 135,439	$ 124,647
Dividend Payout Ratio	61 %	60 %	63 %
Dividends Per Share	$ 2.29	$ 2.17	$ 2.05

Our three-year compound annualized dividend growth rate was 5.9%.

Collateral Requirements

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty. At December 31, 2021, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts. The cash collateral we were required to post at December 31, 2021 was not material.

Guarantees

We provide various guarantees, which represent off-balance sheet commitments, supporting certain of our subsidiaries under specified agreements or transactions. For more information on these guarantees, see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Critical Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. We continue to closely monitor the impacts of COVID-19 and Winter Storm Uri on our critical accounting estimates including, but not limited to, collectibility of customer receivables, recoverability of regulatory assets, impairment risk of goodwill and long-lived assets, valuation of pension assets and liabilities and contingent liabilities. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

The following discussion of our critical accounting estimates should be read in conjunction with Note 1, "Business Description and Significant Accounting Policies" of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Regulation

Our regulated Electric and Gas Utilities are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory commissions based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time.

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

To some degree, each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs) outside of a base rate review. To the extent we are able to pass through such costs to our customers, and a state regulatory commission subsequently determines that such costs should not have been paid by the customers, we may be required to refund such costs.

As of December 31, 2021 and 2020, we had total regulatory assets of $797 million and $278 million, respectively, and total regulatory liabilities of $503 million and $533 million, respectively. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

Goodwill

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 with our financial planning process.

Accounting standards for testing goodwill for impairment require the application of either a qualitative or quantitative assessment to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. Under either the qualitative or quantitative assessment, the estimated fair value of a reporting unit is compared with its carrying amount, including goodwill. If the carrying amount exceeds fair value, then an impairment loss would be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit.

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We have determined that the reporting units for goodwill impairment testing are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which the Chief Operating Decision Maker (CODM) regularly reviews the operating results. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation; 2) estimates of long-term growth rates for our businesses; 3) the determination of an appropriate weighted-average cost of capital or discount rate; and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries. Varying by reporting unit, weighted average cost of capital in the range of 4.9% to 5.1% and long-term growth rate projections of 1.75% were utilized in the goodwill impairment test performed as of October 1, 2021. Although 1.75% was used for a long-term growth rate projection, the short-term projected growth rate is higher with planned recovery of capital investments through rider mechanisms and rate reviews. Under the market approach, we estimate fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, we add a reasonable control premium when calculating fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants.

The estimates and assumptions used in the impairment assessments are based on available market information and we believe they are reasonable. However, variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. For the years ended December 31, 2021, 2020, and 2019, there were no impairment losses recorded. At December 31, 2021, the fair value substantially exceeded the carrying value at all reporting units.

Pension and Other Postretirement Benefits

As described in Note 13 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan, one defined post-retirement healthcare plan and several non-qualified retirement plans. A Master Trust holds the assets for the pension plan. A VEBA trust for the funded portion of the post-retirement healthcare plan has also been established.

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rates, healthcare cost trend rates, expected return on plan assets, compensation increases, retirement rates and mortality rates. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions determined by management and used by actuaries in calculating the amounts. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

The 2022 pension benefit cost for our non-contributory funded pension plan is expected to be $2.2 million compared to $0.8 million in 2021. The increase in the expected 2022 pension benefit cost is driven primarily by lower expected asset returns and a higher discount rate.

The effect of hypothetical changes to selected assumptions on the pension and other postretirement benefit plans would be as follows in thousands of dollars:

		December 31,	
Assumptions	Percentage Change	2021 Increase/(Decrease) PBO/APBO [a]	2022 Increase/(Decrease) Expense - Pretax
Pension			
Discount rate [b]	+/- 0.5	(27,101)/29,688	(1,883)/2,389
Expected return on assets	+/- 0.5	N/A	(2,180)/2,180
OPEB			
Discount rate [b]	+/- 0.5	(2,839)/3,097	47/107
Expected return on assets	+/- 0.5	N/A	(37)/37

(a) Projected benefit obligation (PBO) for the pension plan and accumulated postretirement benefit obligation (APBO) for OPEB plans.
(b) Impact on service cost, interest cost and amortization of gains or losses.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Each entity records income taxes as if it were a separate taxpayer for both federal and state income tax purposes and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be made in the period such determination was made. These adjustments may increase or decrease earnings. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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.

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, but not limited to, the following market risks:

- Commodity price risk associated with our retail natural gas services, wholesale electric power marketing activities and fuel procurement for several of our gas-fired generation assets. Market fluctuations may occur due to unpredictable factors such as weather (Winter Storm Uri), market speculation, inflation, pipeline constraints, and other factors that may impact natural gas and electric energy supply and demand; and

- Interest rate risk associated with future debt, including reduced access to liquidity during periods of extreme capital markets volatility, such as the 2008 financial crisis and the COVID-19 pandemic.

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

To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities and employee conduct. We report any issues or concerns pertaining to the Risk Policies and Procedures to the Audit Committee of our Board of Directors. The Executive Risk Committee, which includes senior level executives, meets at least quarterly and as necessary, to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Commodity Price Risk

Electric and Gas Utilities

Our utilities have various provisions that allow them to pass the prudently-incurred cost of energy through to the customer. To the extent energy prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to reflect billed amounts to match the actual energy cost we incurred. In Colorado, South Dakota and Wyoming, we have ECA or PCA provisions that adjust electric rates when energy costs are higher or lower than the costs included in our tariffs. In Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming, we have GCA provisions that adjust natural gas rates when our natural gas costs are higher or lower than the energy cost included in our tariffs. These adjustments are subject to periodic prudence reviews by the state regulatory commissions.

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 natural gas price volatility. Therefore, as allowed or required by state regulatory 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.

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. See additional information in Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Wholesale Power

We periodically have wholesale power purchase and sale contracts used to manage purchased power costs and load requirements associated with serving our electric customers that are considered derivative instruments and do not qualify for the normal purchase and normal sales exception for derivative accounting. Changes in the fair value of these commodity derivatives are recognized in the Consolidated Statements of Income.

A potential risk related to wholesale power sales is the price risk arising from the sale of power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Black Hills Energy Services

We buy and sell 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 sales. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with fixed price forward contracts to supply gas to our Choice Gas Program customers. The gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period that the underlying hedged item is recognized in earnings.

At December 31, 2021 and 2020, a 10% change in market prices for our derivative instruments would not materially impact pre-tax income, the fair values of our derivative assets and liabilities, or OCI.

See additional commodity risk and derivative information in Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Interest Rate Risk

Periodically, we have engaged in activities to manage risks associated with changes in interest rates. We have utilized pay-fixed interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt refinancings. At December 31, 2021, we had no interest rate swaps in place. Further details of past swap agreements are set forth in Note 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

At December 31, 2021, 91% of our debt is fixed rate debt, which limits our exposure to variable interest rate fluctuations. A hypothetical 100 basis point increase in the benchmark rate on our variable rate debt would have increased annual pretax interest expense by approximately $2.7 million and $2.1 million for the years ended December 31, 2021 and 2020, respectively. See Note 8 for further information on cash amounts outstanding under short- and long-term variable rate borrowings.

We are subject to interest rate risk associated with our pension and post-retirement benefit obligations. Changes in interest rates impact the liabilities associated with these benefit plans as well as the amount of income or expense recognized for these plans. Declines in the value of the plan assets could diminish the funded status of the pension plans and potentially increase the requirements to make cash contributions to these plans. See additional information in Critical Accounting Estimates in Item 7 and Note 13 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Credit Risk

We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. 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, cash collateral requirements, 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, changes in current market conditions, expected losses and any specific customer collection issue that is identified. Our credit exposure at December 31, 2021 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies.

See more information in Notes 1 and 9 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2021, based on the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission "COSO". This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of December 31, 2021.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation's financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2021. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2022, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Accounting - Impact of Rate Regulation on the Financial Statements — Refer to Notes 1 and 2 to the Financial Statements.

Critical Audit Matter Description

The Company is subject to cost-of-service regulation and earnings oversight by state and federal utility commissions (collectively, the “Commissions”), which have jurisdiction over the Company’s electric rates in Colorado, Montana, South Dakota and Wyoming and natural gas rates in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; revenue; operating expenses; and income tax benefit (expense).

Rates are regulated on a state-by-state basis by the relevant state regulatory commissions based on an analysis of the costs, as reviewed and approved in a regulatory proceeding. Rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated its regulatory assets are probable of recovery in current rates or in future proceedings, there is a risk that the Commissions will not judge all costs to have been prudently incurred or that the rate regulation process in which rates are determined will not always result in rates that produce a full recovery of costs and the return on invested capital.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, and (2) a refund or future rate reduction to be provided to customers. Given the uncertainty of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) refunds or future reductions in rates that should be reported as regulatory liabilities. We tested the effectiveness of management’s controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We read relevant regulatory orders issued by the Commissions, procedural memorandums, filings made by the Company, and other publicly available information, as appropriate, to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedence of the Commissions’ treatment of similar costs under similar circumstances. We evaluated the external information and compared it to the Company’s recorded regulatory asset and liability balances for completeness and for any evidence that might contradict management’s assertions.
- We obtained and evaluated an analysis from management regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management’s assertion that amounts are probable of recovery or of a future reduction in rates.
- We inspected minutes of the board of directors to identify any evidence that may contradict management’s assertions regarding probability of recovery or refunds. We also inquired of management regarding current year rate filings and new regulatory assets or liabilities.
- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 15, 2022

We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Company and our report dated February 15, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 15, 2022

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Year ended	December 31, 2021	December 31, 2020	December 31, 2019
	(in thousands, except per share amounts)		
Revenue	$ 1,949,102	$ 1,696,941	$ 1,734,900
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	741,934	492,404	570,829
Operations and maintenance	501,690	495,404	495,994
Depreciation, depletion and amortization	235,953	224,457	209,120
Taxes - property and production	60,096	56,373	52,915
Total operating expenses	1,539,673	1,268,638	1,328,858
Operating income	409,429	428,303	406,042
Other income (expense):			
Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	(154,112)	(144,931)	(139,291)
Interest income	1,708	1,461	1,632
Impairment of investment	—	(6,859)	(19,741)
Other income (expense), net	1,404	(2,293)	(5,740)
Total other income (expense)	(151,000)	(152,622)	(163,140)
Income before income taxes	258,429	275,681	242,902
Income tax (expense)	(7,169)	(32,918)	(29,580)
Net income	251,260	242,763	213,322
Net income attributable to non-controlling interest	(14,516)	(15,155)	(14,012)
Net income available for common stock	$ 236,744	$ 227,608	$ 199,310
Earnings per share of common stock:			
Earnings per share, Basic	$ 3.74	$ 3.65	$ 3.29
Earnings per share, Diluted	$ 3.74	$ 3.65	$ 3.28
Weighted average common shares outstanding:			
Basic	63,219	62,378	60,662
Diluted	63,325	62,439	60,798

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, 2021	December 31, 2020	December 31, 2019
		(in thousands)	
Net income	$ 251,260	$ 242,763	$ 213,322
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $(664), $191 and $1,886, respectively)	1,959	(1,062)	(6,253)
Benefit plan liability adjustments - prior service costs (net of tax of $0, $0 and $2 respectively)	—	—	(8)
Reclassification adjustment of benefit plan liability - net loss (net of tax of $(665), $(958) and $434, respectively)	1,726	1,429	1,179
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $27, $23 and $19, respectively)	(71)	(80)	(58)
Derivative instruments designated as cash flow hedges:			
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(677), $(287) and $(666), respectively)	2,174	2,564	2,185
Net unrealized gains (losses) on commodity derivatives (net of tax of $(980), $14 and $126, respectively)	3,023	(47)	(422)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $502, $(96) and $55, respectively)	(1,549)	505	(362)
Other comprehensive income (loss), net of tax	7,262	3,309	(3,739)
Comprehensive income	258,522	246,072	209,583
Less: comprehensive income attributable to non-controlling interest	(14,516)	(15,155)	(14,012)
Comprehensive income available for common stock	$ 244,006	$ 230,917	$ 195,571

See Note 11 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, 2021	December 31, 2020
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 8,921	$ 6,356
Restricted cash and equivalents	4,889	4,383
Accounts receivable, net	321,652	265,961
Materials, supplies and fuel	150,979	117,400
Derivative assets, current	4,373	1,848
Income tax receivable, net	18,017	19,446
Regulatory assets, current	270,290	51,676
Other current assets	29,012	26,221
Total current assets	808,133	493,291
Property, plant and equipment	7,856,573	7,305,530
Less accumulated depreciation and depletion	(1,407,397)	(1,285,816)
Total property, plant and equipment, net	6,449,176	6,019,714
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	10,770	11,944
Regulatory assets, non-current	526,309	226,582
Other assets, non-current	38,054	37,801
Total other assets, non-current	1,874,587	1,575,781
TOTAL ASSETS	$ 9,131,896	$ 8,088,786

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of December 31, 2021	As of December 31, 2020
	(in thousands, except share amounts)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 217,761	$ 183,340
Accrued liabilities	244,759	243,612
Derivative liabilities, current	1,439	2,044
Regulatory liabilities, current	17,574	25,061
Notes payable	420,180	234,040
Current maturities of long-term debt	—	8,436
Total current liabilities	901,713	696,533
Long-term debt, net of current maturities	4,126,923	3,528,100
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	465,388	408,624
Regulatory liabilities, non-current	485,377	507,659
Benefit plan liabilities	123,925	150,556
Other deferred credits and other liabilities	141,447	134,667
Total deferred credits and other liabilities	1,216,137	1,201,506
Commitments, contingencies and guarantees (Note 3)		
Equity:		
Stockholders’ equity -		
Common stock $1.00 par value; 100,000,000 shares authorized; issued: 64,793,095 and 62,827,179, respectively	64,793	62,827
Additional paid-in capital	1,783,436	1,657,285
Retained earnings	962,458	870,738
Treasury stock at cost - 54,078 and 32,492, respectively	(3,509)	(2,119)
Accumulated other comprehensive income (loss)	(20,084)	(27,346)
Total stockholders’ equity	2,787,094	2,561,385
Non-controlling interest	100,029	101,262
Total equity	2,887,123	2,662,647
TOTAL LIABILITIES AND TOTAL EQUITY	$ 9,131,896	$ 8,088,786

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, 2021	December 31, 2020	December 31, 2019
	(in thousands)		
Operating activities:			
Net income	$ 251,260	$ 242,763	$ 213,322
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	235,953	224,457	209,120
Deferred financing cost amortization	6,968	7,883	7,838
Impairment of investment	—	6,859	19,741
Stock compensation	9,655	5,373	12,095
Deferred income taxes	7,261	38,091	38,020
Employee benefit plans	9,590	11,997	12,406
Other adjustments, net	7,018	11,669	16,485
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(35,707)	2,755	2,052
Accounts receivable and other current assets	(43,170)	(10,843)	7,578
Accounts payable and other current liabilities	10,660	24,659	(34,906)
Regulatory assets	(514,687)	(5,047)	23,619
Regulatory liabilities	(9,533)	(10,706)	(15,158)
Contributions to defined benefit pension plans	—	(12,700)	(12,700)
Other operating activities, net	167	4,653	6,001
Net cash provided by (used in) operating activities	(64,565)	541,863	505,513
Investing activities:			
Property, plant and equipment additions	(677,492)	(767,404)	(818,376)
Other investing activities	13,262	5,740	2,166
Net cash (used in) investing activities	(664,230)	(761,664)	(816,210)
Financing activities:			
Dividends paid on common stock	(145,023)	(135,439)	(124,647)
Common stock issued	118,979	99,278	101,358
Term Loan - borrowings	800,000	—	—
Term Loan - repayments	(800,000)	—	—
Net borrowings (payments) of Revolving Credit Facility and CP Program	186,140	(115,460)	163,880
Long-term debt - issuance	600,000	400,000	1,100,000
Long-term debt - repayments	(8,436)	(8,597)	(905,743)
Distributions to non-controlling interests	(15,749)	(15,839)	(17,901)
Other financing activities	(4,045)	(7,061)	(16,737)
Net cash provided by financing activities	731,866	216,882	300,210
Net change in cash, restricted cash and cash equivalents	3,071	(2,919)	(10,487)
Cash, restricted cash and cash equivalents beginning of year	10,739	13,658	24,145
Cash, restricted cash and cash equivalents end of year	$ 13,810	$ 10,739	$ 13,658
Supplemental cash flow information:			
Cash (paid) refunded during the period:			
Interest (net of amounts capitalized)	$ (142,685)	$ (136,549)	$ (131,774)
Income taxes	$ 1,521	$ 2,172	$ 4,682
Non-cash investing and financing activities:			
Accrued property, plant and equipment purchases at December 31	$ 68,758	$ 72,215	$ 91,491
Increase in capitalized assets associated with asset retirement obligations	$ 2,109	$ 4,774	$ 5,044

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
Balance at December 31, 2018	60,048,567	$ 60,049	44,253	$ (2,510)	$ 1,450,569	$ 700,396	$ (26,916)	$ 105,835	$ 2,287,423
Net income	—	—	—	—	—	199,310	—	14,012	213,322
Other comprehensive (loss), net of tax	—	—	—	—	—	—	(3,739)	—	(3,739)
Dividends on common stock ($2.05 per share)	—	—	—	—	—	(124,647)	—	—	(124,647)
Share-based compensation	103,759	104	(40,297)	2,243	4,729	—	—	—	7,076
Issuance of common stock	1,328,332	1,328	—	—	98,672	—	—	—	100,000
Issuance costs	—	—	—	—	(1,182)	—	—	—	(1,182)
Other	—	—	—	—	—	327	—	—	327
Implementation of ASU 2016-02 Leases	—	—	—	—	—	3,390	—	—	3,390
Distributions to non-controlling interest	—	—	—	—	—	—	—	(17,901)	(17,901)
Balance at December 31, 2019	61,480,658	$ 61,481	3,956	$ (267)	$ 1,552,788	$ 778,776	$ (30,655)	$ 101,946	$ 2,464,069
Net income	—	—	—	—	—	227,608	—	15,155	242,763
Other comprehensive income, net of tax	—	—	—	—	—	—	3,309	—	3,309
Dividends on common stock ($2.17 per share)	—	—	—	—	—	(135,439)	—	—	(135,439)
Share-based compensation	123,578	123	28,536	(1,852)	6,923	—	—	—	5,194
Issuance of common stock	1,222,943	1,223	—	—	98,777	—	—	—	100,000
Issuance costs	—	—	—	—	(1,203)	—	—	—	(1,203)
Implementation of ASU 2016-13 Financial Instruments - - Credit Losses	—	—	—	—	—	(207)	—	—	(207)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(15,839)	(15,839)
Balance at December 31, 2020	62,827,179	$ 62,827	32,492	$ (2,119)	$ 1,657,285	$ 870,738	$ (27,346)	$ 101,262	$ 2,662,647
Net income	—	—	—	—	—	236,744	—	14,516	251,260
Other comprehensive income, net of tax	—	—	—	—	—	—	7,262	—	7,262
Dividends on common stock ($2.29 per share)	—	—	—	—	—	(145,023)	—	—	(145,023)
Share-based compensation	153,719	154	21,586	(1,390)	9,256	—	—	—	8,020
Issuance of common stock	1,812,197	1,812	—	—	118,112	—	—	—	119,924
Issuance costs	—	—	—	—	(1,217)	—	—	—	(1,217)
Other	—	—	—	—	—	(1)	—	—	(1)
Distributions to non-controlling interest	—	—	—	—	—	—	—	(15,749)	(15,749)
Balance at December 31, 2021	64,793,095	$ 64,793	54,078	$ (3,509)	$ 1,783,436	$ 962,458	$ (20,084)	$ 100,029	$ 2,887,123

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

BLACK HILLS CORPORATION
Notes to Consolidated Financial Statements
December 31, 2021, 2020 and 2019

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, conducts our operations through the following reportable segments: Electric Utilities and Gas Utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Segment Reporting

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products and services. All of our operations and assets are located within the United States.

Our Electric Utilities segment includes the operating results of the regulated electric utility operations of Colorado Electric, South Dakota Electric, and Wyoming Electric, which supply regulated electric utility services to areas in Colorado, Montana, South Dakota and Wyoming. We also own and operate non-regulated power generation and mining businesses that are vertically integrated with our Electric Utilities.

In the fourth quarter of 2021, we integrated our power generation and mining businesses within the Electric Utilities segment. The alignment is consistent with the current way our CODM evaluates the performance of the business and makes decisions related to the allocation of resources. Comparative periods presented reflect this change.

Our Gas Utilities segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming.

For further information regarding our segment reporting, see Note 16.

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.

COVID-19 Pandemic

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

The Company's Consolidated Financial Statements reflect estimates and assumptions made by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and reported amounts of revenue and expenses during the reporting periods presented. The Company considered the impacts of COVID-19 on the assumptions and estimates used and determined that, for the years ended December 31, 2021 and 2020, there were no material adverse impacts on the Company's results of operations.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. For additional information on intercompany revenues, see Note 16.

Our Consolidated Statements of Income include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our ownership interest in any jointly-owned electric utility generation facility, wind farm or transmission tie. See Note 6 for additional information.

Variable Interest Entities

We evaluate arrangements and contracts with other entities to determine if they are VIEs and if we are the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, non-controlling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and non-controlling interests at fair value and subsequently account for the VIE as if it were consolidated.

Our evaluation of whether our interest qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement. Black Hills Colorado IPP is a VIE. See additional information in Note 12.

Cash, 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.

Revenue Recognition

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

- Regulated natural gas and electric utility services tariffs - Our Utilities have regulated operations, as defined by ASC 980, *Regulated Operations,* that provide services to regulated customers under tariff rates, charges, terms and conditions of service and prices determined by the jurisdictional regulators designated for our service territories. Our regulated services primarily encompass single performance obligations for delivery of 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 state or federal regulatory commissions 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 segment has 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, we also sell 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. Certain energy sale and purchase transactions with the same counterparty and at the same delivery point are netted to reflect the economic substance of the arrangement.

- Coal supply agreements - Our WRDC mine sells coal primarily under long-term contracts to affiliates for use at their generation facilities. 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 supply agreements, including cost-based agreements with the affiliated regulated utilities, and is variable based on tons delivered.

- Other non-regulated services - Our 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 a variable revenue based on the units delivered or services provided.

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

Revenue Not in Scope of ASC 606

Other revenues included in the tables in Note 4 include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 842, *Leases,* derivative revenue under ASC 815, *Derivatives and Hedging,* and alternative revenue programs revenue under ASC 980, *Regulated Operations*.

Significant Judgments and Estimates

Unbilled Revenue

To the extent that deliveries have occurred but a bill has not been issued, our Utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month, the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts receivable, which is further discussed below.

Additional information is included in Note 4.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable for our Electric and Gas Utilities business segments primarily consists of sales to residential, commercial, industrial, transportation and other customers, all of which do not bear interest. These accounts receivable are stated at billed and estimated unbilled amounts, net of allowance for credit losses. Accounts receivable for our power generation and mining businesses consists of amounts due from sales of electric energy and capacity and coal primarily to affiliates or regional utilities.

We maintain an allowance for credit losses 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 collectability.

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

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.

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

	2021	2020
Billed Accounts Receivable	$ 181,027	$ 146,899
Unbilled Revenue	$ 142,738	$ 126,065
Less Allowance for Credit Losses	$ (2,113)	$ (7,003)
Accounts Receivable, net	$ 321,652	$ 265,961

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

	Balance at Beginning of Year	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
2021	$ 7,003	$ 2,444 [(a)]	$ 3,560	$ (10,894)	$ 2,113
2020	$ 2,444	$ 8,927 [(a)]	$ 4,728	$ (9,096)	$ 7,003
2019	$ 3,209	$ 5,795	$ 3,942	$ (10,502)	$ 2,444

(a) Due to the COVID-19 pandemic, all of our jurisdictions temporarily suspended disconnections due to non-payment for a period of time, which increased our accounts receivable arrears balances. As a result, we increased our allowance for credit losses and bad debt expense for the year ended December 31, 2020 by an incremental $3.3 million. All jurisdiction disconnect moratoriums ended on or before May 3, 2021.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2021	2020
Materials and supplies	$ 86,400	$ 85,250
Fuel	1,267	1,531
Natural gas in storage	63,312	30,619
Total materials, supplies and fuel	$ 150,979	$ 117,400

Materials and supplies represent parts and supplies for business segments. Fuel represents diesel oil and gas used by our Electric Utilities 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.

Investments

In February 2018, we made a contribution of $28 million of assets in exchange for equity securities in a privately held oil and gas company as we divested of our Oil and Gas segment. The carrying value of our investment in the equity securities was recorded at cost. We review this investment on a periodic basis to determine whether a significant event or change in circumstances has occurred that may have an adverse effect on the value of the investment.

During the third quarter of 2019, we assessed our investment for impairment as a result of a deterioration in earnings performance of the privately held oil and gas company and an adverse change in future natural gas prices. Based on the estimated fair value of our investment, we concluded that the carrying value of the investment exceeded fair value. As a result, we recorded a pre-tax impairment loss of $20 million for the three months ended September 30, 2019, which was the difference between the carrying amount and the fair value of the investment at that time.

During the first quarter of 2020, we assessed our investment for impairment as a result of continued adverse changes in future natural gas prices and liquidity concerns at the privately held oil and gas company. Based on the estimated fair value of our investment, we concluded that the carrying value of the investment exceeded fair value. As a result, we recorded a pre-tax impairment loss of $6.9 million for the three months ended March 31, 2020, which was the difference between the carrying value and the fair value of the investment at that time.

The following table presents the carrying value of our investments (in thousands), which are included in Other assets, non-current on the Consolidated Balance Sheets, as of December 31:

	2021	2020
Investment in privately held oil and gas company	$ 1,500	$ 1,500
Cash surrender value of life insurance contracts	12,365	13,628
Other investments	1,616	682
Total investments	$ 15,481	$ 15,810

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. The following table presents AFUDC amounts (in thousands) for the years ended December 31:

	Income Statement Location	2021	2020	2019
AFUDC Borrowed	Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	$ 4,068	$ 5,617	$ 6,556
AFUDC Equity	Other income (expense), net	593	318	472

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 Cushion Gas as property, plant and equipment.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. Estimated removal costs related to our regulated properties that do not have legal retirement obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets 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. The composite depreciation method is applied to regulated utility property. Capitalized mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-regulated power plant components, depreciation is computed on a unit-of-production methodology based on plant hours run.

See Note 5 for additional information.

Asset Retirement Obligations

Accounting standards for AROs 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. 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. Additional information is included in Note 7.

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 are 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.

Our goodwill impairment analysis includes an income approach and a market approach to estimate the fair value of our reporting units. This analysis requires 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.

We believe that goodwill reflects the inherent value of the relatively stable, long-lived cash flows of our Utilities businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our Utilities, and those businesses vertically integrated. Goodwill amounts have not changed since 2016. As of December 31, 2021 and 2020, Goodwill balances were as follows (in thousands):

	Electric Utilities	Gas Utilities	Total
Goodwill	$ 257,244	$ 1,042,210	$ 1,299,454

Our intangible assets represent contract intangibles, easements, rights-of-way, customer listings and trademarks. The finite-lived intangible assets are amortized using a straight-line method based on estimated useful lives; these assets are currently being amortized from 2 years to 40 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

	2021	2020	2019
Intangible assets, net, beginning balance	$ 11,944	$ 13,266	$ 14,337
Amortization expense [(a)]	(1,174)	(1,322)	(1,071)
Intangible assets, net, ending balance	$ 10,770	$ 11,944	$ 13,266

(a) Amortization expense for existing intangible assets is expected to be $1.2 million for each year of the next five years.

Accrued Liabilities

The following amounts by major classification are included in Accrued liabilities on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2021	2020
Accrued employee compensation, benefits and withholdings	$ 74,387	$ 77,806
Accrued property taxes	50,874	47,105
Customer deposits and prepayments	48,814	52,185
Accrued interest	33,680	31,520
Other (none of which is individually significant)	37,004	34,996
Total accrued liabilities	$ 244,759	$ 243,612

Fair Value Measurements

Financial Instruments

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

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

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets other than quoted prices in Level 1, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable, such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

The wholesale electric energy and natural gas commodity contracts for our Utilities are valued using the market approach and include forward strip pricing at liquid delivery points, exchange-traded futures, options, basis swaps and over-the-counter swaps and options (Level 2). For exchange-traded futures, options and basis swap assets and liabilities, fair value was derived using broker quotes validated by the exchange settlement pricing for the applicable contract. For over-the-counter instruments, the fair value is obtained by utilizing a nationally recognized service that obtains observable inputs to compute the fair value, which we validate by comparing our valuation with the counterparty. The fair value of these swaps includes a CVA based on the credit spreads of the counterparties when we are in an unrealized gain position or on our own credit spread when we are in an unrealized loss position.

Additional information on fair value measurements is included in Notes 10 and 13.

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 pricing is clearly and closely related to the asset being purchased or sold. Normal purchase and sales contracts are recognized when the underlying physical transaction is completed under the accrual basis of accounting.

In addition, certain derivative 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, *Regulated Operations*.

We also have some derivatives that qualify for hedge accounting and are designated as cash flow hedges. The gain or loss on these designated derivatives 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 derivative 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 counterparty when a legal right of offset exists. Therefore, the gross amounts are not indicative of either our actual credit or net economic exposures.

See additional information in Notes 9, 10 and 11.

Deferred Financing Costs

Deferred financing costs include loan origination fees, underwriter fees, legal fees and other costs directly attributable to the issuance of debt. Deferred financing costs are amortized over the estimated useful life of the related debt. These costs are presented on the balance sheet as an adjustment to the related debt liabilities. See additional information in Note 8.

Regulatory Accounting

Our regulated Electric Utilities and Gas Utilities are subject to cost-of-service regulation and earnings oversight from federal and state regulatory commissions. Our Electric and Gas Utilities account for income and expense items in accordance with accounting standards for regulated operations. These accounting policies differ in some respects from those used by our non-regulated businesses. Under these regulated operations accounting standards:

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

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

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

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

As of December 31, 2021 and 2020, we had total regulatory assets of $797 million and $278 million respectively, and total regulatory liabilities of $503 million and $533 million respectively. See Note 2 for further information.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Each entity records both federal and state 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.

It is our policy to apply the flow-through method of accounting for ITCs. Under the flow-through method, ITCs 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 ITC 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 benefit (expense) on the Consolidated Statements of Income.

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities or in Deferred income tax liabilities, net on the accompanying Consolidated Balance Sheets. See Note 15 for additional information.

Earnings per Share of Common Stock

Basic earnings per share is computed by dividing Net income available for common stock by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to equity units, outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings per share is as follows for the years ended December 31 (in thousands):

	2021	2020	2019
Net income available for common stock	$ 236,744	$ 227,608	$ 199,310
Weighted average shares - basic	63,219	62,378	60,662
Dilutive effect of:			
Equity compensation	106	61	136
Weighted average shares - diluted	63,325	62,439	60,798
Net income available for common stock, per share - Diluted	$ 3.74	$ 3.65	$ 3.28

The following securities were excluded from the diluted earnings per share computation for the years ended December 31 because of their anti-dilutive nature (in thousands):

	2021	2020	2019
Equity compensation	13	60	1
Anti-dilutive shares excluded from computation of earnings per share	13	60	1

Non-controlling Interests

We account for changes in our controlling interests of subsidiaries according to ASC 810*, Consolidation.* ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that non-controlling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the non-controlling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional detail on non-controlling interests.

Share-Based Compensation

We account for our share-based compensation arrangements in accordance with ASC 718, *Compensation-Stock Compensation*, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures. See additional information in Note 14.

Recently Issued Accounting Standards

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

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*, which was subsequently amended by ASU 2021-01. The standard provides relief for companies preparing for discontinuation of interest rates, such as LIBOR, and allows optional expedients and exceptions for applying GAAP to contracts, hedging relationships and other transactions affected by reference rate reform if certain criteria are met. The amendments in this update are elective and are effective upon the ASU issuance through December 31, 2022. We are currently evaluating if we will apply the optional guidance as we assess the impact of the discontinuance of LIBOR on our current arrangements and the potential impact on our financial position, results of operations and cash flows.

Recently Adopted Accounting Standards

Simplifying the Accounting for Income Taxes, ASU 2019-12

In December 2019, the FASB issued ASU 2019-12, *Simplifying the Accounting for Income Taxes* as part of its overall simplification initiative to reduce costs and complexity in applying accounting standards while maintaining or improving the usefulness of the information provided to users of the financial statements. Amendments include removal of certain exceptions to the general principles of ASC 740, *Income Taxes*, and simplification in several other areas such as accounting for a franchise tax (or similar tax) that is partially based on income. We adopted this standard prospectively on January 1, 2021. Adoption of this standard did not have an impact on our financial position, results of operations or cash flows.

(2) REGULATORY MATTERS

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

	2021	2020
Regulatory assets		
Winter Storm Uri [a]	$ 509,025	$ —
Deferred energy and fuel cost adjustments [b]	59,973	39,035
Deferred gas cost adjustments [b]	9,488	3,200
Gas price derivatives [b]	2,584	2,226
Deferred taxes on AFUDC [b]	7,457	7,491
Employee benefit plans and related deferred taxes [c]	88,923	116,598
Environmental [b]	1,385	1,413
Loss on reacquired debt [b]	21,011	22,864
Deferred taxes on flow-through accounting [b]	63,243	47,515
Decommissioning costs [b]	5,961	8,988
Gas supply contract termination [b]	—	2,524
Other regulatory assets [b]	27,549	26,404
Total regulatory assets	796,599	278,258
Less current regulatory assets	(270,290)	(51,676)
Regulatory assets, non-current	$ 526,309	$ 226,582
Regulatory liabilities		
Deferred energy and gas costs [b]	$ 6,113	$ 13,253
Employee benefit plan costs and related deferred taxes [c]	32,241	40,256
Cost of removal [b]	179,976	172,902
Excess deferred income taxes [c]	264,042	285,259
Other regulatory liabilities [c]	20,579	21,050
Total regulatory liabilities	502,951	532,720
Less current regulatory liabilities	(17,574)	(25,061)
Regulatory liabilities, non-current	$ 485,377	$ 507,659

____
(a) Timing of Winter Storm Uri incremental cost recovery and associated carrying costs vary by jurisdiction and some jurisdictions are still subject to pending applications with the respective utility commission. See further information below.
(b) Recovery of costs, but we are not allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

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

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

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our Electric Utilities' 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 regulatory 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 regulatory commissions. The recovery period for these costs is less than a year.

Deferred Gas Cost Adjustments - 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 regulatory commissions. The recovery period for these costs is less than a year.

Gas Price Derivatives - Our regulated Gas Utilities, as allowed or required by state regulatory 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, 2021 are hedged over a maximum forward term of two years.

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

Employee Benefit Plans and Related Deferred Taxes - 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. In addition, this regulatory asset includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Environmental - Environmental costs associated with certain former manufactured gas plant sites. These costs are first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining cost will be requested for recovery in future rate filings. Recovery for these specific environmental costs has not yet been approved by the applicable state regulatory commission and therefore, the recovery period is unknown at this time.

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.

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 and result in lower utility rates in the year in which the tax benefits are realized. 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 Liquefied Natural Gas Plant decommissioning costs as a regulatory asset and received approval in 2020 to begin recovering those costs over three years.

Gas Supply Contract Termination - With the 2016 SourceGas acquisition, we assumed agreements requiring the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. The prices to be paid under these agreements exceeded market prices at the time of acquisition. We received state utility commission approvals to terminate these agreements and Orders allowing us to create a regulatory asset for the net contract buyout costs with recovery over five years. We terminated the contract and settled the liability on April 29, 2016.

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

Deferred Energy and Gas Costs **-** Deferred energy and gas costs that have been over-recovered through customer rates and will be returned to customers in future periods.

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. See Note 15 for additional information.

Recent Regulatory Activity

Winter Storm Uri

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

Our Utilities submitted Winter Storm Uri cost recovery applications in our state jurisdictions seeking to recover $546 million of these incremental costs through separate tracking mechanisms over a weighted-average recovery period of 3.5 years. These incremental cost estimates are subject to adjustments as final decisions are issued by the respective utility commissions. In these applications, we sought approval to recover carrying costs. For the year ended December 31, 2021, $4.1 million of carrying costs were accrued and recorded to a regulatory asset. We are also seeking recovery of $13 million of previously disclosed Winter Storm Uri incremental costs through our existing regulatory mechanisms.

To date, Iowa Gas, Kansas Gas, Nebraska Gas and South Dakota Electric received commission approval for Winter Storm Uri cost recovery. Additionally, Arkansas Gas and Wyoming Gas received approval for interim cost recovery subject to a final decision on carrying costs and recovery periods at a later date. Colorado Gas and Colorado Electric filed settlement agreements for their applications with final rates to be implemented in 2022. These settlements are subject to final approval by the CPUC. For the year ended December 31, 2021, our Utilities collected $40 million of Winter Storm Uri incremental costs and carrying costs from customers.

TCJA

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company remeasured our deferred income taxes at the 21% federal tax rate as of December 31, 2017. In 2018 and 2019, the Company successfully delivered several of these tax benefits from the TCJA to its utility customers.

In 2020, regulatory proceedings resolved the last of the Company’s open dockets seeking approval of its TCJA plans. As a result, the Company relieved certain TCJA-related liabilities, which resulted in an increase to net income for the year ended December 31, 2020 of $4.0 million.

On December 30, 2020, an administrative law judge approved a settlement of Colorado Electric’s plan to provide $9.3 million of TCJA-related bill credits to its customers. The bill credits, which represent a disposition of excess deferred income tax benefits resulting from the TCJA, were delivered to customers in February 2021. The settlement agreement further provided for Colorado Electric to deliver annual bill credits to customers, starting in April 2021, until remaining excess deferred income tax regulatory liabilities associated with the TCJA are fully amortized. In April 2021, Colorado Electric delivered $0.9 million of TCJA-related bill credits to customers.

On January 26, 2021, the NPSC approved Nebraska Gas’s plan to provide $2.9 million of TCJA-related bill credits to its customers. The bill credits, which represent a disposition of excess deferred income tax benefits resulting from the TCJA, were delivered to customers in June 2021.

These Colorado Electric and Nebraska Gas bill credits, which resulted in a reduction in revenue, were offset by a reduction in income tax expense and resulted in a minimal impact to Net income for the year ended December 31, 2021.

As part of the 2021 rate review settlement agreement discussed further below, Kansas Gas will deliver $3.0 million of TCJA and state tax reform benefits to customers, annually, for each of the next three years starting in 2022 (approximately $9.1 million of total benefits expected to be delivered).

Arkansas Gas

On December 10, 2021, Arkansas Gas filed a rate review with the APSC seeking recovery of significant infrastructure investments in its 7,200-mile natural gas pipeline system. The rate review requests $22 million in new annual revenue with a capital structure of 50.9% equity and 49.1% debt and a return on equity of 10.2%. The request seeks to finalize rates in the fourth quarter of 2022.

Colorado Gas

Rate Reviews and SSIR

On June 1, 2021, Colorado Gas filed a rate review with the CPUC seeking recovery of significant infrastructure investments in its 7,000-mile natural gas pipeline system. In the fourth quarter of 2021, Colorado Gas reached a settlement agreement with the CPUC staff and various intervenors for a general rate increase, which was subsequently approved by an administrative law judge. New rates were effective January 1, 2022, and the settlement is expected to generate $6.5 million of new annual revenue. The new revenue is based on a return on equity of 9.2% and a capital structure of 50.3% equity and 49.7% debt.

On September 11, 2020, in accordance with the final Order from the rate review filed on February 1, 2019, Colorado Gas filed a SSIR proposal with the CPUC that would recover safety and integrity focused investments in its system for five years. On July 6, 2021, Colorado Gas received approval from the CPUC for its SSIR proposal to recover these investments for three years effective January 1, 2022. The return on SSIR investments will be the current weighted-average cost of long-term debt.

Iowa Gas

Rate Review

On June 1, 2021, Iowa Gas filed a rate review with the IUB seeking recovery of significant infrastructure investments in its 5,000-mile natural gas pipeline system. On December 28, 2021, the IUB approved a settlement agreement with all intervening parties for a general rate increase. The settlement will shift $2.2 million of rider revenue to base rates and is expected to generate $3.7 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 9.6%. Final rates were enacted on January 1, 2022, and replaced interim rates effective June 11, 2021.

Kansas Gas

Rate Review

On May 7, 2021, Kansas Gas filed a rate review and rider renewal with the KCC seeking recovery of significant infrastructure investments in its 4,600-mile natural gas pipeline system. On December 30, 2021, Kansas Gas received approval from the KCC on its Global Settlement agreement with KCC staff and various intervenors for a general rate increase and renewal of its safety and integrity rider. The settlement shifted $6.6 million of rider revenue to base rates, effective January 1, 2022, and also allowed rider renewal for at least five more years.

Nebraska Gas

Jurisdictional Consolidation and Rate Review

On January 26, 2021, Nebraska Gas received approval from the NPSC to consolidate rate schedules into a new, single statewide structure and recover significant infrastructure investments in its 13,000-mile natural gas pipeline system. Final rates were enacted on March 1, 2021, which replaced interim rates effective September 1, 2020. The approval shifted $4.6 million of SSIR revenue to base rates and is expected to generate $6.5 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 9.5%. The approval also included an extension of the SSIR for five years and an expansion of this mechanism across the consolidated jurisdictions.

South Dakota Electric

FERC Formula Rate

The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2021, the annual revenue requirement for the FERC Transmission Formula Rate was $26 million and included estimated weighted average capital additions of $5.0 million for 2020 and 2021 combined.

Black Hills Wyoming and Wyoming Electric

Wygen I FERC Filing

On October 15, 2020, the FERC approved a settlement agreement that represents a resolution of all issues in the joint application filed by Wyoming Electric and Black Hills Wyoming on August 2, 2019 for approval of a new 60 MW PPA. Under the terms of the settlement, Wyoming Electric will continue to receive 60 MW of capacity and energy from the Wygen I power plant. The new agreement commenced on January 1, 2022, replaced the existing PPA and will continue for 11 years.

(3) COMMITMENTS, CONTINGENCIES AND GUARANTEES

Power Purchase and Transmission Services Agreements

Through our subsidiaries, we have the following significant long-term power purchase contracts and transmission services agreement with non-affiliated third-parties:

Subsidiary	Contract Type	Counterparty	Fuel Type	Quantity (MW)	Expiration Date
Colorado Electric [(a)]	PPA	PRPA	Wind	60	May 31, 2030
Colorado Electric	PPA	PRPA	Coal	25	June 30, 2024
Colorado Electric	PPA	TC Colorado Solar, LLC	Solar	200	Pending Completion [(b)]
South Dakota Electric	PPA	PacifiCorp	Coal	50	December 31, 2023
South Dakota Electric [(c)]	Transmission Services Agreement	PacifiCorp	N/A	50	December 31, 2023
South Dakota Electric	PPA	PRPA	Wind	12	September 30, 2029
South Dakota Electric	PPA	Fall River Solar, LLC	Solar	80	Pending Completion [(d)]
Wyoming Electric [(e)]	PPA	Happy Jack	Wind	30	September 3, 2028
Wyoming Electric [(f)]	PPA	Silver Sage	Wind	30	September 30, 2029

(a) Colorado Electric sells the wind energy purchased under this PPA to City of Colorado Springs as discussed below.
(b) On January 31, 2022, TC Colorado Solar, LLC (TC Solar) provided termination notice of the PPA to Colorado Electric. Colorado Electric has disputed TC Solar's right to termination and pursuant to the agreement, has initiated discussions with TC Solar. This agreement relates to a new solar facility to be constructed and would expire 15 years after construction completion.
(c) This is a firm point-to-point transmission service agreement providing the ability to deliver a maximum of 50 MW of capacity and associated energy.
(d) This agreement relates to a new solar facility currently being constructed and will expire 20 years after construction completion, which is expected by the end of 2022.
(e) Under a separate intercompany PSA, Wyoming Electric sells 50% of the facility output to South Dakota Electric.
(f) Under a separate intercompany PSA, Wyoming Electric sells 67% of the facility output to South Dakota Electric.

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

Subsidiary	Contract Type	Counterparty	Fuel Type	2021	2020	2019
Colorado Electric	PPA	PRPA	Wind	$ 4,246	$ 2,791	$ —
Colorado Electric	PPA	PRPA	Coal	$ 4,447	$ 4,524	$ 1,802
South Dakota Electric	PPA	PacifiCorp	Coal	$ 8,923	$ 5,897	$ 7,477
South Dakota Electric	Transmission Services Agreement	PacifiCorp	N/A	$ 1,783	$ 1,776	$ 1,741
South Dakota Electric	PPA	PRPA	Wind	$ 596	$ 715	$ 688
Wyoming Electric	PPA	Happy Jack	Wind	$ 3,544	$ 4,531	$ 3,936
Wyoming Electric	PPA	Silver Sage	Wind	$ 4,717	$ 6,203	$ 5,366

Power Purchase Agreements - Related Parties

Wyoming Electric had a PPA with Black Hills Wyoming scheduled to expire on December 31, 2022, which provided 60 MW of unit-contingent capacity and energy from Black Hills Wyoming's Wygen I facility. On October 15, 2020, the FERC approved a settlement agreement in the joint application filed by Wyoming Electric and Black Hills Wyoming on August 2, 2019 for approval of a new 60 MW PPA. Under the terms of the settlement, Wyoming Electric will continue to receive 60 MW of capacity and energy from the Wygen I facility. The new agreement commenced on January 1, 2022, replaced the existing PPA and will continue for 11 years.

Black Hills Electric Generation provides the wind energy generated from Busch Ranch II to Colorado Electric through a PPA, which expires in November 2044.

Black Hills Electric Generation provides its 14.5 MW share of energy generated from Busch Ranch I to Colorado Electric through a PPA, which expires in October 2037.

Colorado Electric's PPA with Black Hills Colorado IPP, expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines.

Purchase Commitments

We maintain natural gas supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated baseload gas volumes are established prior to the beginning of the month under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month based on requirements in accordance with the terms of the individual contract.

Our Gas Utilities segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and are therefore, for purposes of this disclosure, carried out for 60 days. At December 31, 2021, the long-term commitments to purchase quantities of natural gas under contracts indexed to the following forward indices were as follows (in MMBtus):

	2022	2023	2024	2025	2026	Thereafter
El Paso - Bondad Station	31,000	—	—	—	—	—
Kern River - Opal	9,300	—	—	—	—	—
El Paso - San Juan Basin	182,550	—	—	—	—	—
Enable East Pipeline	1,825,000	450,000	—	—	—	—
Northern Natural Gas - Demarc	1,614	—	—	—	—	—
Northern Natural Gas - Ventura	1,810,000	1,840,000	1,820,000	—	—	—
Northwest Pipeline - Wyoming	1,531,700	1,510,000	910,000	—	—	—
ONEOK - Oklahoma	5,475,000	5,475,000	5,490,000	4,560,000	—	—
Southern Star Central Gas Pipeline	113,130	—	—	—	—	—
Panhandle Eastern Pipe Line	1,609,680	2,737,500	—	—	—	—
	12,588,974	12,012,500	8,220,000	4,560,000	—	—

Purchases under these contracts totaled $61 million, $25 million and $7 million for 2021, 2020 and 2019, respectively.

Other Gas Supply Agreements

Our Utilities also purchase natural gas, including transportation and storage capacity to meet customers' needs, under short-term and long-term purchase contracts. These contracts extend to 2044.

The following is a schedule of unconditional purchase obligations required under the power purchase, transmission services and natural gas transportation and storage agreements (in thousands):

	Power purchase and transmission services agreements [(a)]	Natural gas transportation and storage agreements
2022	$ 23,985	$ 143,750
2023	$ 11,678	$ 119,923
2024	$ 2,738	$ 82,428
2025	$ —	$ 58,669
2026	$ —	$ 36,503
Thereafter	$ —	$ 60,429

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

Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- On July 1, 2020, Colorado Electric entered into a PSA with the City of Colorado Springs to sell up to 60 MW of wind energy purchased from PRPA under a separate 60 MW PPA discussed above. This PSA with the City of Colorado Springs expires June 30, 2025.

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, South Dakota Electric will provide MDU with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- South Dakota Electric has an agreement to provide MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, South Dakota Electric will provide the City of Gillette with its first 23 MW from its other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, which has an initial term through September 3, 2034 and would be renewed annually on September 3 thereafter, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

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

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

- South Dakota Electric had an agreement that expired December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals.

- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year Economy Energy PSA 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.

Lease Agreements

Lessee

We lease from third parties certain office and operation center facilities, communication tower sites, equipment and materials storage. Our leases have remaining terms ranging from less than one year to 34 years, including options to extend that are reasonably certain to be exercised. Our operating and finance leases were not material to the Company's Consolidated Financial statements.

Lessor

We lease to third parties certain generating station ground leases, communication tower sites and a natural gas pipeline. These leases have remaining terms ranging from less than one year to 34 years. Lease revenue was not material for the years ended December 31, 2021, 2020 and 2019.

As of December 31, 2021, scheduled maturities of operating lease payments to be received in future years were as follows (in thousands):

	Operating Leases
2022	$ 2,173
2023	2,204
2024	2,125
2025	2,070
2026	1,881
Thereafter	51,233
Total lease receivables	$ 61,686

Environmental Matters

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

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond of $4.1 million with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under our land leases for our wind generation facilities, we are required to reclaim land where we have placed wind turbines. The reclamation liabilities are recorded at the present value of the estimated future cost to reclaim the land.

Under its mining permit, WRDC is required to reclaim all land where it has mined reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 7 for additional information.

Manufactured Gas Processing

In 2008, we acquired whole and partial liabilities for former manufactured gas processing sites in Nebraska and Iowa, which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.2 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. We also have a $1.4 million regulatory asset for manufactured gas processing sites; see Note 2 for additional information.

As of December 31, 2021, we had $2.6 million accrued for remediation of Iowa's manufactured gas processing site as the landowner. As of December 31, 2021, we had $0.6 million accrued for remediation of Nebraska's manufactured gas processing site as the land owner. These liabilities are included in Other deferred credits and other liabilities on our Consolidated Balance Sheets. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

Legal Proceedings

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

We record gain contingencies when realized, and expected recoveries under applicable insurance contracts when we are assured of recovery.

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

Guarantees

We have entered into various parent company-level guarantees providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. These guarantees do not represent incremental consolidated obligations, but rather, represent guarantees of subsidiary obligations to allow those subsidiaries to conduct business without posting other forms of assurance. The agreements, which are off-balance sheet commitments, include support for business operations, indemnification for reclamation and surety bonds. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by these guarantees, such liabilities are included in our Consolidated Balance Sheets.

See Note 8 for additional information on our off-balance sheet Letters of Credit commitment.

We had the following guarantees in place as of (in thousands):

Nature of Guarantee	Maximum Exposure at December 31, 2021
Indemnification for reclamation/surety bonds	$ 55,867
Guarantees supporting business transactions	$ 370,558
	$ 426,425

(4) REVENUE

The following tables depict the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition for each of the reportable segments, for the years ended December 31, 2021, 2020 and 2019. Sales tax and other similar taxes are excluded from revenues.

Year ended December 31, 2021	Electric Utilities	Gas Utilities	Inter-company Revenues	Total
Customer types:		(in thousands)		
Retail	$ 711,448	$ 913,725	$ —	$ 1,625,173
Transportation	—	158,053	(428)	157,625
Wholesale	30,848	—	—	30,848
Market - off-system sales	41,682	396	—	42,078
Transmission/Other	52,945	39,365	(17,200)	75,110
Revenue from contracts with customers	836,923	1,111,539	(17,628)	1,930,834
Other revenues	5,335	13,326	(393)	18,268
Total revenues	$ 842,258	$ 1,124,865	$ (18,021)	$ 1,949,102
Timing of revenue recognition:				
Services transferred at a point in time	$ 27,141	$ —	$ —	$ 27,141
Services transferred over time	809,782	1,111,539	(17,628)	1,903,693
Revenue from contracts with customers	$ 836,923	$ 1,111,539	$ (17,628)	$ 1,930,834

Year ended December 31, 2020	Electric Utilities	Gas Utilities	Inter-company Revenues	Total
Customer types:		(in thousands)		
Retail	$ 636,902	$ 765,922	$ —	$ 1,402,824
Transportation	—	154,581	(526)	154,055
Wholesale	24,845	—	—	24,845
Market - off-system sales	15,512	260	—	15,772
Transmission/Other	55,422	43,658	(15,772)	83,308
Revenue from contracts with customers	732,681	964,421	(16,298)	1,680,804
Other revenues	6,176	10,249	(288)	16,137
Total revenues	$ 738,857	$ 974,670	$ (16,586)	$ 1,696,941
Timing of revenue recognition:				
Services transferred at a point in time	$ 27,089	$ —	$ —	$ 27,089
Services transferred over time	705,592	964,421	(16,298)	1,653,715
Revenue from contracts with customers	$ 732,681	$ 964,421	$ (16,298)	$ 1,680,804

Year ended December 31, 2019	Electric Utilities	Gas Utilities	Inter-company Revenues	Total
Customer types:		(in thousands)		
Retail	$ 632,936	$ 817,840	$ —	$ 1,450,776
Transportation	—	143,390	(1,042)	142,348
Wholesale	28,464	—	—	28,464
Market - off-system sales	16,081	691	—	16,772
Transmission/Other	53,750	47,725	(13,443)	88,032
Revenue from contracts with customers	731,231	1,009,646	(14,485)	1,726,392
Other revenues	8,124	384	—	8,508
Total revenues	$ 739,355	$ 1,010,030	$ (14,485)	$ 1,734,900
Timing of revenue recognition:				
Services transferred at a point in time	$ 27,180	$ —	$ —	$ 27,180
Services transferred over time	704,051	1,009,646	(14,485)	1,699,212
Revenue from contracts with customers	$ 731,231	$ 1,009,646	$ (14,485)	$ 1,726,392

(5) PROPERTY, PLANT AND EQUIPMENT

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

	2021		2020		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$ 1,452,055	41	$ 1,417,951	40	32	45
Electric transmission	546,126	49	517,794	49	43	50
Electric distribution	1,000,619	47	959,453	46	45	49
Integrated Generation	720,490	30	716,479	31	2	59
Plant acquisition adjustment [(a)]	4,870	32	4,870	32	32	32
General	266,935	28	259,010	28	25	31
Total electric plant in service	3,991,095		3,875,557			
Construction work in progress	181,451		95,266			
Total electric plant	4,172,546		3,970,823			
Less accumulated depreciation and depletion	(1,016,738)		(960,993)			
Electric plant net of accumulated depreciation and depletion	$ 3,155,808		$ 3,009,830			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 9 years remaining.

Gas Utilities	2021 Property, Plant and Equipment	2021 Weighted Average Useful Life (in years)	2020 Property, Plant and Equipment	2020 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Gas plant:						
Production	$ 14,841	40	$ 15,603	40	24	46
Gas transmission	645,550	58	578,278	54	22	71
Gas distribution	2,394,352	53	2,115,082	53	45	59
Cushion gas - depreciable [(a)]	3,539	28	3,539	28	28	28
Cushion gas - not depreciable [(a)]	42,478	N/A	39,184	N/A	N/A	N/A
Storage	56,289	38	55,481	38	27	52
General	474,964	21	438,217	19	3	23
Total gas plant in service	3,632,013		3,245,384			
Construction work in progress	37,860		67,229			
Total gas plant	3,669,873		3,312,613			
Less accumulated depreciation	(389,115)		(323,679)			
Gas plant net of accumulated depreciation	$ 3,280,758		$ 2,988,934			

(a) Depreciation of Cushion Gas is determined by the respective regulatory jurisdiction in which the Cushion Gas resides.

2021	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years) Minimum	Lives (in years) Maximum
Corporate	$ 5,694	$ 8,460	$ 14,154	$ (1,544)	$ 12,610	10	10	22

2020	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years) Minimum	Lives (in years) Maximum
Corporate	$ 5,692	$ 16,402	$ 22,094	$ (1,144)	$ 20,950	10	10	22

(6) JOINTLY OWNED FACILITIES

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

Wyodak Plant

South Dakota Electric owns a 20% interest in the Wyodak Plant while PacifiCorp owns the remaining ownership interest and operates the Wyodak Plant. South Dakota Electric receives its proportionate share of the Wyodak Plant's capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying South Dakota Electric with coal for its share of the Wyodak Plant, our mine supplies PacifiCorp's share of the coal under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.

Transmission Tie

South Dakota Electric owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the Transmission Tie), an AC-DC-AC transmission tie. Basin Electric Power Cooperative owns the remaining 65% interest in the Transmission Tie. South Dakota Electric is committed to pay its proportionate share of the additions and replacements and operating and maintenance expenses of the Transmission Tie.

Wygen III

South Dakota Electric owns 52% of the Wygen III generation facility. MDU and the City of Gillette each own an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. South Dakota Electric retains responsibility for plant operations. Our mine supplies fuel to Wygen III for the life of the plant.

Wygen I

Black Hills Wyoming owns 76.5% of the Wygen I plant while MEAN owns the remaining ownership interest. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our mine during the life of the facility. Black Hills Wyoming retains responsibility for plant operations.

At December 31, 2021, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Less Accumulated Depreciation	Plant Net of Accumulated Depreciation
Wyodak Plant	$ 118,637	$ 882	$ (70,468)	$ 49,051
Transmission Tie	$ 24,544	$ 287	$ (6,922)	$ 17,909
Wygen III	$ 142,199	$ 635	$ (26,598)	$ 116,236
Wygen I	$ 120,565	$ 399	$ (53,784)	$ 67,180

Jointly Owned Facilities - Related Party

Busch Ranch I

Colorado Electric owns 50% of Busch Ranch I while Black Hills Electric Generation owns the remaining 50% ownership interest. Each company is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm over the life of the facility. Colorado Electric retains responsibility for operations of the wind farm. Black Hills Electric Generation provides its share of energy from the wind farm to Colorado Electric through a PPA, which expires in October 2037.

Cheyenne Prairie

Cheyenne Prairie serves the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 40 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 100 MW unit that is jointly-owned by South Dakota Electric (58 MW) and Wyoming Electric (42 MW). BHSC is responsible for plant operations.

Corriedale

Corriedale serves as the dedicated wind energy supply for Renewable Ready customers in South Dakota and Wyoming. The 52.5 MW wind farm is jointly-owned by South Dakota Electric (32.5 MW) and Wyoming Electric (20 MW). BHSC is responsible for operations of the wind farm.

(7) ASSET RETIREMENT OBLIGATIONS

We have identified legal obligations related to reclamation of mining sites; removal of fuel tanks, transformers containing polychlorinated biphenyls, and an evaporation pond; and reclamation of wind turbine sites at our Electric Utilities segment. In addition, we have identified legal obligations related to retirement of gas pipelines and wells at our Gas Utilities and removal of asbestos at our Utilities. We periodically review and update estimated costs related to these AROs. The actual cost may vary from estimates due to regulatory requirements, changes in technology and increased labor, materials and equipment costs.

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, 2020	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	December 31, 2021
Electric Utilities	$ 29,157	$ —	$ (978)	$ 1,315	$ 595	$ 30,089
Gas Utilities [(a)]	42,274	—	(66)	1,733	1,514	45,455
Total	71,431	$ —	$ (1,044)	$ 3,048	$ 2,109	$ 75,544

	December 31, 2019	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	December 31, 2020
Electric Utilities [(b)] [(c)]	$ 28,120	$ 1,217	$ (185)	$ 1,230	$ (1,225)	$ 29,157
Gas Utilities [(d)]	36,085	4,782	(132)	1,539	—	42,274
Total	$ 64,205	$ 5,999	$ (317)	$ 2,769	$ (1,225)	$ 71,431

(a) The Revisions to Prior Estimates were primarily driven by changes in estimates associated with natural gas wells.
(b) Liabilities incurred were related to new wind assets.
(c) The Revisions to Prior Estimates were primarily driven by changes in estimated costs associated with back-filling the pit with overburden removed during the mining process.
(d) Liabilities incurred were driven by an increase in gas pipeline miles; which increases our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with federal regulations.

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.

(8) FINANCING

Short-term debt

We had the following Notes payable outstanding at the Consolidated Balance Sheets date (in thousands):

	December 31, 2021		December 31, 2020	
	Balance Outstanding	Letters of Credit [(a)]	Balance Outstanding	Letters of Credit [(a)]
Revolving Credit Facility	$ —	$ 27,209	$ —	$ 24,730
CP Program	420,180	—	234,040	—
Total	$ 420,180	$ 27,209	$ 234,040	$ 24,730

(a) Letters of credit are off-balance sheet commitments that reduce the borrowing capacity available on our corporate Revolving Credit Facility.

Revolving Credit Facility and CP Program

On July 19, 2021, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 19, 2026 with two one year extension options (subject to consent from lenders). This Revolving Credit Facility is similar to the former revolving credit facility, which includes an accordion feature that allows us to increase total commitments up to $1.0 billion with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment. 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 current 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, 2021. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at December 31, 2021.

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 short-term borrowings (payments) during 2021 were $186 million. As of December 31, 2021, the weighted average interest rate on short-term borrowings was 0.30%.

Total accumulated deferred financing costs on the Revolving Credit Facility of $8.9 million are being amortized over its estimated useful life and were included in Interest expense on the accompanying Consolidated Statements of Income. See below for additional details.

Term Loan

On February 24, 2021, we entered into a nine-month, $800 million unsecured term loan to provide additional liquidity and to meet our cash needs related to the incremental fuel, purchased power and natural gas costs from Winter Storm Uri. The term loan, carried no prepayment penalty and was subject to the same covenant requirements as our Revolving Credit Facility. We repaid $200 million of this term loan in the first quarter of 2021. Proceeds from the August 26, 2021 public debt offering (discussed below) were used to repay the remaining balance on this term loan.

Long-term debt

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

	Due Date	Interest Rate at December 31, 2021	Balance Outstanding December 31, 2021	Balance Outstanding December 31, 2020
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$ 525,000	$ 525,000
Senior unsecured notes due 2024	August 23, 2024	1.04%	600,000	—
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 2029	October 15, 2029	3.05%	400,000	400,000
Senior unsecured notes, due 2030	June 15, 2030	2.50%	400,000	400,000
Senior unsecured notes due 2033	May 1, 2033	4.35%	400,000	400,000
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300,000	300,000
Senior unsecured notes, due 2049	October 15, 2049	3.88%	300,000	300,000
Corporate term loan due 2021	June 7, 2021	N/A	—	1,436
Total Corporate debt			3,625,000	3,026,436
Less unamortized debt discount			(6,125)	(7,013)
Total Corporate debt, net			3,618,875	3,019,423
South Dakota Electric				
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Total South Dakota Electric debt			340,000	340,000
Less unamortized debt discount			(74)	(78)
Total South Dakota Electric debt, net			339,926	339,922
Wyoming Electric				
Industrial development revenue bonds due 2021[(a)]	September 1, 2021	N/A	—	7,000
Industrial development revenue bonds due 2027[(a) (b)]	March 1, 2027	0.15%	10,000	10,000
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	75,000
Total Wyoming Electric debt			195,000	202,000
Less unamortized debt discount			—	—
Total Wyoming Electric debt, net			195,000	202,000
Total long-term debt			4,153,801	3,561,345
Less current maturities			—	8,436
Less unamortized deferred financing costs [(c)]			26,878	24,809
Long-term debt, net of current maturities and deferred financing costs			$ 4,126,923	$ 3,528,100

(a) Variable interest rate.
(b) A reimbursement agreement is in place with Wells Fargo on behalf of Wyoming Electric for the 2009A bonds of $10 million due March 1, 2027. In the case of default, we hold the assumption of liability for drawings on Wyoming Electric’s Letter of Credit attached to these bonds.
(c) Includes deferred financing costs associated with our Revolving Credit Facility of $2.5 million and $1.0 million as of December 31, 2021 and December 31, 2020, respectively.

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

2022	$	—
2023	$	525,000
2024	$	600,000
2025	$	—
2026	$	300,000
Thereafter	$	2,735,000

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2021. See below for additional information.

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.

Amortization of Deferred Financing Costs

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

Deferred Financing Costs Remaining at December 31, 2021	Amortization Expense for the years ended December 31, 2021	2020	2019
$ 26,878	$ 3,769	$ 3,272	$ 3,242

Debt Transactions

On August 26, 2021, we completed a public debt offering which consisted of $600 million, 1.037% three-year senior unsecured notes due August 23, 2024. The notes include an optional redemption provision and may be redeemed, in whole or in part, without premium, on or after February 23, 2022. The proceeds from the offering, which were net of $3.7 million of deferred financing costs, were used to repay amounts outstanding under our term loan entered into on February 24, 2021.

On June 17, 2020, we completed a public debt offering which consisted of $400 million of 2.50% 10-year senior unsecured notes due June 15, 2030. The proceeds were used to repay short-term debt and for working capital and general corporate purposes.

Debt Covenants

Revolving Credit Facility

Under our Revolving Credit Facility, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding.

We were in compliance with our covenants at December 31, 2021 as shown below:

	As of December 31, 2021	Covenant Requirement	
Consolidated Indebtedness to Capitalization Ratio	62.1%	Less than	65%

Wyoming Electric

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of December 31, 2021, we were in compliance with these financial covenants.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs.

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.

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, 2021, the amount of restricted net assets at our Utilities that may not be distributed to our utility holding company in the form of a loan or dividend was approximately $155 million.

South Dakota Electric and Wyoming Electric are generally limited to the amount of dividends allowed to be paid to our utility holding company under certain financing agreements.

Equity

At-the-Market Equity Offering Program

On August 3, 2020, we filed a shelf registration and DRSPP with the SEC. In conjunction with these shelf filings, we renewed the ATM. The renewed ATM program, which allows us to sell shares of our common stock, is the same as the prior program other than the aggregate value increased from $300 million to $400 million and a forward sales option was incorporated. This forward sales option allows us to sell our shares through the ATM program at the current trading price without actually issuing any shares to satisfy the sale until a future date. Under the ATM, shares may be offered from time to time pursuant to a sales agreement dated August 3, 2020. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC.

During the twelve months ended December 31, 2021, we issued a total of 1,812,197 shares of common stock under the ATM for $119 million, net of $1.1 million in issuance costs. We did not issue any shares of common stock under the ATM during the twelve months ended December 31, 2020. During the twelve months ended December 31, 2019, we issued a total of 1,328,332 shares of common stock under the ATM for $99 million, net of $1.2 million in issuance costs.

February 2020 Equity Issuance

On February 27, 2020, we issued 1.2 million shares of common stock to a single investor through an underwritten registered transaction at a price of $81.77 per share for proceeds of $99 million, net of $1.0 million of issuance costs. The shares of common stock were offered pursuant to our shelf registration statement filed with the SEC.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued new shares until March 1, 2018, after which we began purchasing shares on the open market. At December 31, 2021, there were 116,306 shares of unissued stock available for future offering under the DRSPP.

Preferred Stock

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding as of December 31, 2021 and 2020.

(9) RISK MANAGEMENT AND DERIVATIVES

Market and Credit Risk Disclosures

Our activities in the energy industry 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, but not limited to, the following market risks:

- Commodity price risk associated with our retail natural gas and wholesale electric power marketing activities and our fuel procurement for several of our gas-fired generation assets, which include market fluctuations due to unpredictable factors such as the COVID-19 pandemic, weather (Winter Storm Uri), market speculation, inflation, pipeline constraints, and other factors that may impact natural gas and electric supply and demand; and

- Interest rate risk associated with future debt, including reduced access to liquidity during periods of extreme capital markets volatility, such as the 2008 financial crisis and the COVID-19 pandemic.

Credit Risk

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

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, cash collateral requirements, 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, changes in current market conditions, expected losses and any specific customer collection issue that is identified. Our credit exposure at December 31, 2021 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies.

Derivatives and Hedging Activity

Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

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 natural gas price volatility. 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.

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 state regulatory commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income.

We periodically have wholesale power purchase and sale contracts used to manage purchased power costs and load requirements associated with serving our electric customers that are considered derivative instruments due to not qualifying for the normal purchase and normal sales exception to derivative accounting. Changes in the fair value of these commodity derivatives are recognized in the Consolidated Statements of Income.

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 sales during time frames ranging from January 2022 through October 2024. 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 gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and reclassified into earnings in the same period that the underlying hedged item is recognized in earnings. Effectiveness of our hedging position is evaluated at least quarterly.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our utilities are comprised of both short and long positions. We had the following net long positions as of:

	December 31, 2021		December 31, 2020	
	Notional (MMBtus)	Maximum Term (months) [a]	Notional (MMBtus)	Maximum Term (months) [a]
Natural gas futures purchased	590,000	3	620,000	3
Natural gas options purchased, net	3,100,000	3	3,160,000	3
Natural gas basis swaps purchased	870,000	3	900,000	3
Natural gas over-the-counter swaps, net [b]	4,570,000	34	3,850,000	17
Natural gas physical commitments, net [c]	16,416,677	24	17,513,061	22
Electric wholesale contracts [c]	—	0	219,000	12

(a) Term reflects the maximum forward period hedged.
(b) As of December 31, 2021, 1,830,000 of natural gas over-the-counter swaps purchased were designated as cash flow hedges.
(c) Volumes exclude derivative contracts that qualify for the normal purchase, normal sales exception permitted by GAAP.

We have certain derivative contracts which contain credit provisions. These credit provisions may require the Company to post collateral when credit exposure to the Company is in excess of a negotiated line of unsecured credit. At December 31, 2021, the Company posted $2.1 million related to such provisions, which is included in Other current assets on the Consolidated Balance Sheets.

Derivatives by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis aside from the netting of asset and liability positions. Netting of positions is permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements that allow us to settle positive and negative positions.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in thousands):

	Balance Sheet Location	2021	2020
Derivatives designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ 2,017	$ 181
Noncurrent commodity derivatives	Other assets, non-current	18	43
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	—	(108)
Total derivatives designated as hedges		$ 2,035	$ 116
Derivatives not designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ 2,356	$ 1,667
Noncurrent commodity derivatives	Other assets, non-current	804	151
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	(1,439)	(1,936)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(20)	—
Total derivatives not designated as hedges		$ 1,701	$ (118)

Derivatives Designated as Hedge Instruments

The impact of cash flow hedges on our Consolidated Statements of Income is presented below for the years ended December 31, 2021, 2020 and 2019. Note that this presentation does not reflect the gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic profit or loss we realized when the underlying physical and financial transactions were settled.

Derivatives in Cash Flow Hedging Relationships	2021	2020	2019	Income Statement Location	2021	2020	2019
	Amount of Gain/(Loss) Recognized in OCI				Amount of Gain/(Loss) Reclassified from AOCI into Income		
	(in thousands)				(in thousands)		
Interest rate swaps	$ 2,851	$ 2,851	$ 2,851	Interest expense	$ (2,851)	$ (2,851)	$ (2,851)
Commodity derivatives	1,952	540	(965)	Fuel, purchased power and cost of natural gas sold	2,051	(601)	417
Total	$ 4,803	$ 3,391	$ 1,886		$ (800)	$ (3,452)	$ (2,434)

As of December 31, 2021, $0.9 million of net losses related to our interest rate swaps and commodity derivatives are expected to be reclassified from AOCI into earnings within the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income for the years ended December 31, 2021, 2020 and 2019. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

Derivatives Not Designated as Hedging Instruments	Income Statement Location	2021	2020	2019
		Amount of Gain/(Loss) on Derivatives Recognized in Income		
		(in thousands)		
Commodity derivatives - Electric	Fuel, purchased power and cost of natural gas sold	$ (144)	$ 144	$ —
Commodity derivatives - Natural Gas	Fuel, purchased power and cost of natural gas sold	2,599	1,640	(1,100)
		$ 2,455	$ 1,784	$ (1,100)

As discussed above, financial instruments used in our regulated Gas Utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to these financial instruments in our Gas Utilities were $2.6 million and $2.2 million at December 31, 2021 and 2020, respectively. For our Electric Utilities, the unrealized gains and losses arising from these derivatives are recognized in the Consolidated Statements of Income.

(10) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

Derivatives

The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments.

	As of December 31, 2021				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting (a)	Total
	(in thousands)				
Assets:					
Commodity derivatives - Gas Utilities	$ —	$ 7,569	$ —	$ (2,374)	$ 5,195
Commodity derivatives - Electric Utilities	—	—	—	—	—
Total	$ —	$ 7,569	$ —	$ (2,374)	$ 5,195
Liabilities:					
Commodity derivatives - Gas Utilities	$ —	$ 3,273	$ —	$ (1,814)	$ 1,459
Commodity derivatives - Electric Utilities		$ —		$ —	$ —
Total	$ —	$ 3,273	$ —	$ (1,814)	$ 1,459

(a) As of December 31, 2021, $2.4 million of our commodity derivative gross assets and $1.8 million of our commodity derivative gross liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

	As of December 31, 2020				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting (a)	Total
Assets:					
Commodity derivatives - Gas Utilities	$ —	2,504	$ —	$ (1,527)	$ 977
Commodity derivatives - Electric Utilities	—	1,065	—	—	1,065
Total	$ —	$ 3,569	$ —	$ (1,527)	$ 2,042
Liabilities:					
Commodity derivatives - Gas Utilities	$ —	$ 2,675	$ —	$ (1,552)	$ 1,123
Commodity derivatives - Electric Utilities	—	921	—	—	921
Total	$ —	$ 3,596	$ —	$ (1,552)	$ 2,044

(a) As of December 31, 2020, $1.5 million of our commodity derivative assets and $1.6 million of our commodity derivative liabilities, as well as related gross collateral amounts, were subject to master netting agreements.

Pension and Postretirement Plan Assets

A discussion of the fair value of our Pension and Postretirement Plan assets is included in Note 13.

Nonrecurring Fair Value Measurement

A discussion of the fair value of our investment in equity securities of a privately held oil and gas company, a Level 3 asset, is included in Note 1.

Other Fair Value Measurements

The carrying amount of cash and cash equivalents, restricted cash and equivalents and short-term borrowings approximates fair value due to their liquid or short-term nature. Cash, cash equivalents and restricted cash are classified in Level 1 in the fair value hierarchy. Notes payable consist of commercial paper borrowings and are not traded on an exchange; therefore, they are classified as Level 2 in the fair value hierarchy.

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

	2021		2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current maturities [(a)]	$ 4,126,923	$ 4,570,619	$ 3,536,536	$ 4,208,167

(a) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy. Carrying amount of long-term debt is net of deferred financing costs.

(11) OTHER COMPREHENSIVE INCOME

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

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

	Location on the Consolidated Statements of Income	Amount Reclassified from AOCI December 31, 2021	December 31, 2020
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ (2,851)	$ (2,851)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	2,051	(601)
		(800)	(3,452)
Income tax	Income tax benefit (expense)	175	383
Total reclassification adjustments related to cash flow hedges, net of tax		$ (625)	$ (3,069)
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$ 98	$ 103
Actuarial gain (loss)	Operations and maintenance	(2,391)	(2,387)
		(2,293)	(2,284)
Income tax	Income tax benefit (expense)	638	935
Total reclassification adjustments related to defined benefit plans, net of tax		$ (1,655)	$ (1,349)
Total reclassifications		$ (2,280)	$ (4,418)

Balances by classification included within AOCI, net of tax on the accompanying Consolidated Balance Sheets were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2020	$ (12,558)	$ 2	$ (14,790)	$ (27,346)
Other comprehensive income (loss) before reclassifications	—	3,023	1,959	4,982
Amounts reclassified from AOCI	2,174	(1,549)	1,655	2,280
As of December 31, 2021	$ (10,384)	$ 1,476	$ (11,176)	$ (20,084)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2019	$ (15,122)	$ (456)	$ (15,077)	$ (30,655)
Other comprehensive income (loss) before reclassifications	—	(47)	(1,062)	(1,109)
Amounts reclassified from AOCI	2,564	505	1,349	4,418
As of December 31, 2020	$ (12,558)	$ 2	$ (14,790)	$ (27,346)

(12) VARIABLE INTEREST ENTITY

Black Hills Colorado IPP owns and operates a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. In 2016, Black Hills Electric Generation sold a 49.9%, non-controlling interest in Black Hills Colorado IPP 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.

The accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated is specified under ASC 810, *Consolidation*. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that non-controlling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet.

Net income available for common stock for the years ended December 31, 2021, 2020 and 2019 was reduced by $15 million, $15 million, and $14 million, respectively, attributable to this non-controlling interest. The net income allocable to the non-controlling interest holder is based on ownership interest with the exception of certain agreed upon adjustments. Distributions of net income attributable to this non-controlling interest are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Black Hills Colorado IPP has been determined to be a VIE in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of December 31 (in thousands):

	2021	2020
Assets:		
Current assets	$ 13,220	$ 13,604
Property, plant and equipment of variable interest entities, net	$ 189,079	$ 190,637
Liabilities:		
Current liabilities	$ 5,841	$ 5,318

(13) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

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

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

Defined Benefit Pension Plan

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, 2021, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 22% to 30% return-seeking assets and 70% to 78% liability-hedging assets.

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

Plan Assets

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

	2021	2020
Equity	15%	21%
Real estate	7	3
Fixed income	74	69
Cash	1	3
Hedge funds	3	4
Total	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are funded on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plan

BHC sponsors a retiree healthcare plan (Healthcare Plan) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plan for participating business units are pre-funded via VEBA trusts. Pre-65 retirees as well as a grandfathered group of post-65 retirees receive their retiree medical benefits through the Black Hills self-insured retiree medical plans. Healthcare coverage for post-65 Medicare-eligible retirees is provided through an individual market healthcare exchange.

We fund the Healthcare Plan on a cash basis as benefits are paid. The Healthcare Plan provides for partial pre-funding via VEBA trusts. 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, Iowa and Kansas. We do not pre-fund the Healthcare Plan for those employees outside Arkansas, Iowa and Kansas.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Healthcare benefits include company and participant paid premiums. Contributions for the years ended December 31 were as follows (in thousands):

	2021	2020
Defined Contribution Plan		
Company retirement contributions	$ 11,332	$ 10,455
Company matching contributions	$ 15,938	$ 15,240

	2021	2020
Defined Benefit Plans		
Defined Benefit Pension Plan	$ —	$ 12,700
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 6,432	$ 6,058
Supplemental Non-Qualified Defined Benefit Plans	$ 2,576	$ 2,674

While we do not have required contributions, we expect to make $3.9 million in contributions to our Pension Plan in 2022.

Fair Value Measurements

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

Pension Plan	December 31, 2021					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Investments
Common Collective Trust - Cash and Cash Equivalents	$ —	$ 6,009	$ —	$ 6,009	$ —	$ 6,009
Common Collective Trust - Equity	—	70,262	—	70,262	—	70,262
Common Collective Trust - Fixed Income	—	339,219	—	339,219	—	339,219
Common Collective Trust - Real Estate	—	—	—	—	30,407	30,407
Hedge Funds	—	—	—	—	12,490	12,490
Total investments measured at fair value	$ —	$ 415,490	$ —	$ 415,490	$ 42,897	$ 458,387

Pension Plan	December 31, 2020					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Investments
Common Collective Trust - Cash and Cash Equivalents	—	16,810	—	16,810	—	16,810
Common Collective Trust - Equity	—	100,311	—	100,311	—	100,311
Common Collective Trust - Fixed Income	—	324,845	—	324,845	—	324,845
Common Collective Trust - Real Estate	—	—	—	—	14,301	14,301
Hedge Funds	—	—	—	—	17,454	17,454
Total investments measured at fair value	$ —	$ 441,966	$ —	$ 441,966	$ 31,755	$ 473,721

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

Non-pension Defined Benefit Postretirement Healthcare Plan	December 31, 2021				
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	Total Investments
Cash and Cash Equivalents	$ 7,972	$ —	$ —	$ 7,972	$ 7,972
Total investments measured at fair value	$ 7,972	$ —	$ —	$ 7,972	$ 7,972

Non-pension Defined Benefit Postretirement Healthcare Plan	December 31, 2020				
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	Total Investments
Cash and Cash Equivalents	$ 8,165	$ —	$ —	$ 8,165	$ 8,165
Total investments measured at fair value	$ 8,165	$ —	$ —	$ 8,165	$ 8,165

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

Pension Plan

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

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

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

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

Hedge Funds: These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined, aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. 10% of the shares may be redeemed at the end of each month with a 15-day notice and full redemptions are available at the end of each quarter with 60-day notice and is limited to a percentage of the total net assets value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

Non-pension Defined Benefit Postretirement Healthcare Plan

Cash and Cash Equivalents: This represents an investment in Northern Institutional Government Assets Portfolio, which is a government money market fund. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Other Plan Information

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

Employee Benefit Plan Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
As of December 31,	2021	2020	2021	2020	2021	2020
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 514,008	$ 485,376	$ 55,054	$ 54,088	$ 70,238	$ 65,277
Service cost [(a)]	5,038	5,411	3,149	1,579	2,237	2,056
Interest cost	9,313	13,426	706	1,099	1,058	1,649
Actuarial (gain) loss	(14,037)	47,064	(1,073)	962	(5,165)	5,804
Amendments	(561)	—	—	—	—	—
Benefits paid	(35,499)	(37,269)	(2,576)	(2,674)	(6,432)	(6,058)
Plan participants' contributions	—	—	—	—	1,548	1,510
Projected benefit obligation at end of year	$ 478,262	$ 514,008	$ 55,260	$ 55,054	$ 63,484	$ 70,238

(a) For the year ended December 31, 2020, Service Cost for the Supplemental Non-qualified Defined Benefit Plans includes a $1.4 million correction of a prior year overstatement of Projected benefit obligation.

Fair Value Employee Benefit Plan Assets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan [(a)]	
As of December 31,	2021	2020	2021	2020	2021	2020
Change in fair value of plan assets:						
Beginning fair value of plan assets	$ 473,721	$ 434,284	$ —	$ —	$ 8,165	$ 8,305
Investment income (loss)	20,165	64,006	—	—	(35)	33
Employer contributions	—	12,700	2,576	2,674	4,726	4,374
Retiree contributions	—	—	—	—	1,548	1,511
Benefits paid	(35,499)	(37,269)	(2,576)	(2,674)	(6,432)	(6,058)
Ending fair value of plan assets	$ 458,387	$ 473,721	$ —	$ —	$ 7,972	$ 8,165

(a) Assets of VEBA trusts.

In 2012, we froze our Pension Plan and closed it to new participants. Since then, we have implemented various de-risking strategies including lump sum buyouts, the purchase of annuities and the reduction of return-seeking assets over time to a more liability-hedged portfolio. As a result, capital markets volatility driven by the COVID-19 pandemic did not materially affect our unfunded status.

Amounts Recognized in the Consolidated Balance Sheets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
As of December 31,	2021	2020	2021	2020	2021	2020
Regulatory assets	$ 67,403	$ 86,677	$ —	$ —	$ 11,660	$ 16,102
Current liabilities	$ —	$ —	$ 2,156	$ 1,927	$ 4,584	$ 4,931
Non-current liabilities	$ 19,872	$ 40,287	$ 53,104	$ 53,127	$ 50,949	$ 57,142
Regulatory liabilities	$ 3,830	$ 3,607	$ —	$ —	$ 2,447	$ 2,140

Accumulated Benefit Obligation

As of December 31,	Defined Benefit Pension Plan 2021	Defined Benefit Pension Plan 2020	Supplemental Non-qualified Defined Benefit Plans 2021	Supplemental Non-qualified Defined Benefit Plans 2020	Non-pension Defined Benefit Postretirement Healthcare Plan 2021	Non-pension Defined Benefit Postretirement Healthcare Plan 2020
Accumulated Benefit Obligation	$ 466,505	$ 498,815	$ 55,260	$ 54,779	$ 63,484	$ 70,238

Components of Net Periodic Expense

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
For the years ended December 31,	2021	2020	2019	2021	2020	2019	2021	2020	2019
Service cost [(a)]	$ 5,038	$ 5,411	$ 5,383	$ 3,149	$ 1,579	$ 4,995	$ 2,237	$ 2,056	$ 1,815
Interest cost	9,313	13,426	17,374	706	1,099	1,295	1,058	1,649	2,247
Expected return on assets	(20,876)	(22,591)	(24,401)	—	—	—	(136)	(182)	(230)
Net amortization of prior service cost	—	—	26	—	2	2	(434)	(546)	(398)
Recognized net actuarial loss (gain)	7,315	8,372	3,763	1,754	1,702	535	466	20	—
Net periodic expense	$ 790	$ 4,618	$ 2,145	$ 5,609	$ 4,382	$ 6,827	$ 3,191	$ 2,997	$ 3,434

(a) For the year ended December 31, 2020, Service Cost for the Supplemental Non-qualified Defined Benefit Plans includes a $1.4 million correction of a prior year overstatement of Projected benefit obligation.

For the years ended December 31, 2021, 2020 and 2019, Service costs were recorded in Operations and maintenance expense while non service costs were recorded in Other expense on the Consolidated Statements of Income.

AOCI Amounts (After-Tax)

As of December 31,	Defined Benefit Pension Plan 2021	Defined Benefit Pension Plan 2020	Supplemental Non-qualified Defined Benefit Plans 2021	Supplemental Non-qualified Defined Benefit Plans 2020	Non-pension Defined Benefit Postretirement Healthcare Plan 2021	Non-pension Defined Benefit Postretirement Healthcare Plan 2020
Net (gain) loss	$ 4,398	$ 5,511	$ 7,159	$ 9,323	$ (308)	$ 100
Prior service cost (gain)	(46)	—	—	—	(27)	(144)
Total amounts included in AOCI, after-tax not yet recognized as components of net periodic expense	$ 4,352	$ 5,511	$ 7,159	$ 9,323	$ (335)	$ (44)

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plan		
Weighted-average assumptions used to determine benefit obligations:	2021	2020	2019	2021	2020	2019	2021	2020	2019
Discount rate	2.88 %	2.56 %	3.27 %	2.77 %	2.41 %	3.14 %	2.79 %	2.41 %	3.15 %
Rate of increase in compensation levels	3.08 %	3.34 %	3.49 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A

Weighted-average assumptions used to determine net periodic benefit cost for plan year:	Defined Benefit Pension Plan 2021	2020	2019	Supplemental Non-qualified Defined Benefit Plans 2021	2020	2019	Non-pension Defined Benefit Postretirement Healthcare Plan 2021	2020	2019
Discount rate [(a)]	2.56 %	3.27 %	4.40 %	2.41 %	3.14 %	4.34 %	2.41 %	3.15 %	4.28 %
Expected long-term rate of return on assets [(b)]	4.50 %	5.25 %	6.00 %	N/A	N/A	N/A	1.80 %	2.35 %	3.00 %
Rate of increase in compensation levels	3.34 %	3.49 %	3.52 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A

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

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

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

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

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
2022	$ 26,249	$ 2,156	$ 5,806
2023	$ 27,133	$ 2,224	$ 5,334
2024	$ 27,683	$ 2,410	$ 5,042
2025	$ 28,650	$ 2,757	$ 4,865
2026	$ 28,968	$ 2,782	$ 4,752
2027-2031	$ 144,422	$ 12,553	$ 21,615

(14) SHARE-BASED COMPENSATION PLANS

Our 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options, performance shares and performance share units. We had 416,325 shares available to grant at December 31, 2021.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2021, total unrecognized compensation expense related to non-vested stock awards was approximately $14 million and is expected to be recognized over a weighted-average period of two years. Stock-based compensation expense, which is included in Operations and maintenance on the accompanying Consolidated Statements of Income, was as follows for the years ended December 31 (in thousands):

	2021	2020	2019
Stock-based compensation expense	$ 9,655	$ 5,373	$ 12,095

Restricted Stock

The fair value of restricted stock and restricted stock unit awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over three years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and restricted stock units at December 31, 2021, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Balance at January 1, 2021	196	$ 69.05
Granted	118	65.64
Vested	(83)	67.85
Forfeited	(12)	69.59
Balance at December 31, 2021	219	$ 67.64

The weighted-average grant-date fair value of restricted stock granted and the total fair value of shares vested during the years ended December 31, were as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested
		(in thousands)
2021	$ 65.64	$ 5,400
2020	$ 69.49	$ 6,722
2019	$ 73.66	$ 8,438

As of December 31, 2021, there was $11 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 2.2 years.

Performance Share Plan

Prior to 2021, certain officers of the Company and its subsidiaries became participants in a market-based performance share award plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

These performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.1 million at December 31, 2021 would be reclassified as a liability.

The outstanding performance periods at December 31, 2021 were as follows (shares in thousands):

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
January 1, 2020	January 1, 2020 - December 31, 2022	36	0%	200%
January 1, 2019	January 1, 2019 - December 31, 2021	36	0%	200%

A summary of the status of the Performance Share Plan at December 31, 2021 was as follows:

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value [(a)]	Shares	Weighted-Average Fair Value at December 31, 2021
	(in thousands)		(in thousands)	
Performance Shares balance at beginning of period	61	$ 69.71	61	
Granted	—	—	—	
Forfeited	—	—	—	
Vested	(25)	61.82	(25)	
Performance Shares balance at end of period	36	$ 68.14	36	$ 31.51

(a) The grant date fair values for the performance shares granted in 2020 and 2019 were determined by Monte Carlo simulation using a blended volatility of 18% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

The weighted-average grant-date fair value of performance share awards granted was as follows in the years ended:

	Weighted Average Grant Date Fair Value
December 31, 2020	$ 81.42
December 31, 2019	$ 68.72

Performance plan payouts have been as follows (in thousands):

Performance Period	Year Paid	Stock Issued	Cash Paid	Total Intrinsic Value
January 1, 2018 to December 31, 2020	2021	28	$ 1,647	$ 3,294
January 1, 2017 to December 31, 2019	2020	14	$ 1,100	$ 2,199
January 1, 2016 to December 31, 2018	2019	44	$ 2,860	$ 5,720

On January 25, 2022, the Compensation Committee of our Board of Directors determined that the Company’s total shareholder return for the January 1, 2018 to December 31, 2020 performance period was at the 30th percentile of its peer group and confirmed a payout equal to 40.17% of target shares, valued at $1.0 million. The payout was fully accrued at December 31, 2021.

Performance Share Units

Beginning in 2021, certain officers of the Company, and its subsidiaries, were granted performance share units which have a three-year vesting period, do not have voting rights until vested, and are subject to three specified conditions. A market condition of relative total shareholder return, and two equally weighted performance metrics of average earnings per share and the average cost to serve. The units are paid 100% in common stock should conditions be met and can range from 0% to 200% of the target award. Dividend equivalents are accrued during the vesting period and paid out based on the final number of shares awarded. In the event of participant’s death or retirement at age 55 or older, awarded vest on a pro-rata basis over the three-year period.

Performance Share Units - Market Condition

The fair value of each share unit is based on the Company''s closing price at December 31 of the year prior to the award and a Monte Carlo simulation. The Monte Carlo simulation is used to estimate expected share payout based on the Company's TSR for a three-year performance period relative to the designated peer group beginning January 1 of the award year.

	2021
Fair value of share units award	$64.97
Three-year risk-free rate	0.17%
Black Hills Corporation's common stock volatility	33%
Volatility range for the peer group	25 % - 76%

Performance Share Units - Performance Condition

A performance condition share unit vests at the end of the three-year performance period if the specified performance conditions are achieved. The conditions are based on the Company's average earnings per share and the average cost to serve. The grant-date fair value for an individual outcome of a performance condition is determined by the closing common share price on the grant date.

The following table summarizes the performance share unit activity for the year ended December 31, 2021:

	Performance Share Units - Market Condition		Performance Share Units - Performance Condition	
	Share Units	Weighted-Average Fair Value per Share Unit	Share Units	Weighted-Average Fair Value per Share Unit
Nonvested at January 1, 2021	—	$ —	—	$ —
Granted	32,903	64.97	21,948	61.45
Nonvested at December 31, 2021	32,903	$ 64.97	21,948	$ 61.45

As of December 31, 2021, there was $2.9 million of unrecognized compensation expense related to outstanding performance share/unit plans that is expected to be recognized over a weighted-average period of 1.8 years.

(15) INCOME TAXES

Winter Storm Uri

As discussed in Note 2 above, our Utilities submitted cost recovery applications which seek to recover incremental costs from Winter Storm Uri through a regulatory mechanism. We expect to recover these costs from customers over several years. Winter Storm Uri costs, which will be deductible in our 2021 tax return, created a net deferred tax liability which had a balance of $124 million as of December 31, 2021. The deferred tax liability will reverse with the same timing as the costs are recovered from our customers.

The income tax deduction recognized from Winter Storm Uri will create a $509 million NOL in our 2021 federal income tax return and a $375 million NOL in our state income tax returns. Our federal NOL carryforwards related to Winter Storm Uri and other recent adjustments no longer expire due to the TCJA; however, our state NOL carryforwards expire at various dates from 2022 to 2041. We do not anticipate material changes to our valuation allowance against the state NOL carryforwards from Winter Storm Uri. Therefore, we did not record an additional valuation allowance against the state NOL carryforwards as of December 31, 2021.

CARES Act

On March 27, 2020, President Trump signed the CARES Act, which contained, in part, an allowance for deferral of the employer portion of Social Security employment tax liabilities until 2021 and 2022, as well as a COVID-19 employee retention tax credit of up to $5,000 per eligible employee.

During the year ended December 31, 2020, we utilized the payroll tax deferral provision which allowed us to defer payment of approximately $10 million of Social Security employment tax liabilities, of which $4.8 million was subsequently paid in 2021 and the remaining portion will be paid in 2022. During the year ended December 31, 2021, we completed our study of the CARES Act employee retention tax credits and recognized $1.2 million of gross payroll tax credits.

TCJA

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the federal and state utility commissions, which could have a material impact on the Company’s future results of operations, cash flows or financial position. 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, 2021, the Company has amortized, or provided bill credits for, $23 million of the regulatory liability. The portion that was eligible for amortization under the average rate assumption method in 2021 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.

Income Tax Expense (Benefit)

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

	2021	2020	2019
Current:			
Federal	$ 574	$ (6,020)	$ (8,578)
State	(666)	847	138
Current income tax (benefit)	(92)	(5,173)	(8,440)
Deferred:			
Federal	2,170	35,672	34,551
State	5,091	2,419	3,469
Deferred income tax expense	7,261	38,091	38,020
Income tax expense	$ 7,169	$ 32,918	$ 29,580

Effective Tax Rates

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

	2021	2020	2019
Federal statutory rate	21.0 %	21.0 %	21.0 %
State income tax (net of federal tax effect)	1.2	2.4	1.5
Non-controlling interest [(a)]	(1.2)	(1.2)	(1.2)
Tax credits[(b)]	(8.4)	(9.2)	(3.9)
Flow-through adjustments [(c)]	(3.2)	(1.6)	(2.4)
Uncertain Tax Benefits	0.3	1.5	—
Valuation Allowance	—	0.7	—
Other tax differences	(0.2)	0.6	(1.6)
Amortization of excess deferred income tax expense [(d)]	(3.1)	(2.3)	(1.2)
TCJA bill credits [(e)]	(3.6)	—	—
Effective Tax Rate	2.8 %	11.9 %	12.2 %

____
(a) The effective tax rate reflects the income attributable to the non-controlling interest in Black Hills Colorado IPP for which a tax provision was not recorded.
(b) In 2020, the Company completed a research and development study which encompassed tax years from 2013 to 2019.
(c) Flow-through adjustments related primarily to accounting method changes for tax purposes that allow us to take a current tax deduction for repair costs, certain indirect costs and gain deferral. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.
(d) Primarily TCJA - see above.
(e) As discussed in Note 2 above, Colorado Electric and Nebraska Gas bill credits, which represent a disposition of excess deferred income tax benefits resulting from the TCJA, were delivered to customers in 2021. These bill credits, which resulted in a reduction in revenue, were offset by a reduction in income tax expense and resulted in a minimal impact to Net income for the year ended December 31, 2021.

Table of Contents

Deferred Tax Assets and Liabilities

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

	2021	2020
Deferred tax assets:		
Regulatory liabilities	$ 77,099	$ 90,535
State tax credits	23,342	23,339
Federal NOL [a]	227,535	96,155
State NOL [a]	33,639	9,914
Partnership	13,395	15,601
Credit Carryovers	68,646	51,445
Other deferred tax assets	31,996	40,143
Less: Valuation allowance	(14,719)	(13,943)
Total deferred tax assets	460,933	313,189
Deferred tax liabilities:		
Accelerated depreciation, amortization and other property-related differences	(597,284)	(551,137)
Regulatory assets [a]	(124,582)	(28,007)
Goodwill	(45,471)	(30,590)
State deferred tax liability [a]	(109,136)	(73,910)
Other deferred tax liabilities	(49,848)	(38,169)
Total deferred tax liabilities	(926,321)	(721,813)
Net deferred tax liability	$ (465,388)	$ (408,624)

(a) Increase primarily driven by Winter Storm Uri — see above.

Net Operating Loss Carryforwards

At December 31, 2021, we have federal and state NOL carryforwards that will expire at various dates as follows (in thousands):

	Amounts	Expiration Dates		
Federal NOL Carryforward	$ 476,033	2022	to	2037
Federal NOL Carryforward	$ 607,465		No expiration	
State NOL Carryforward [a]	$ 572,203	2022	to	2041

(a) The carryforward balance is reflected on the basis of apportioned tax losses to jurisdictions imposing state income taxes.

As of December 31, 2021, we had a $1.1 million valuation allowance against the state NOL carryforwards. Our 2021 analysis of the ability to utilize such NOLs resulted in no increase in the valuation allowance. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

Unrecognized Tax Benefits

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

Changes in Uncertain Tax Positions:	2021	2020	2019
Beginning balance	$ 8,383	$ 4,165	$ 3,583
Additions for prior year tax positions	448	3,788	446
Reductions for prior year tax positions	(732)	(1,313)	(862)
Additions for current year tax positions	2,455	1,743	998
Ending balance	$ 10,554	$ 8,383	$ 4,165

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $5.1 million.

We recognized no interest expense associated with income taxes for the years ended December 31, 2021, December 31, 2020 and December 31, 2019. We had no accrued interest (before tax effect) associated with income taxes at December 31, 2021 and December 31, 2020.

The Company is subject to federal income tax as well as income tax in various state and local jurisdictions. Black Hills Gas, Inc. and subsidiaries, which filed a separate consolidated tax return from BHC and subsidiaries through March 31, 2018, is under examination by the IRS for 2014. BHC is no longer subject to examination for tax years prior to 2017.

As of December 31, 2021, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2022.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2021, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards	Amounts	Expiration Year
ITC	$ 23,060	2023 to 2041
Research and development	$ 282	No expiration

As of December 31, 2021, we had a $13.6 million valuation allowance against the state ITC carryforwards. Our 2021 analysis of the ability to utilize such ITC resulted in a $0.8 million increase in the valuation allowance, which resulted in an increase to tax expense of $0.8 million. The valuation allowance adjustment was primarily attributable to changes in forecasted future state taxable income.

(16) BUSINESS SEGMENT INFORMATION

Our chief operating decision maker (CODM) reviews financial information presented on an operating segment basis for purposes of making decisions and assessing financial performance. Our CODM assesses the performance of our operating segments based on operating income.

In the prior year, we had reported four operating segments: Electric Utilities, Gas Utilities, Power Generation and Mining. In the fourth quarter of 2021, we changed our operating segments to align with the revised manner in which our CODM reviews our financial performance and allocates resources. Our power generation and mining businesses, which were previously presented as separate operating segments, are now part of our Electric Utilities segment. This change aligns with our vertically integrated business model for our Electric Utilities. Comparative periods presented reflect this change.

Our operating segments are equivalent to our reportable segments.

Segment information was as follows (in thousands):

Total Assets (net of intercompany eliminations) as of December 31,	2021	2020
Electric Utilities	$ 3,796,662	$ 3,602,233
Gas Utilities	5,246,370	4,376,204
Corporate and Other	88,864	110,349
Total assets	$ 9,131,896	$ 8,088,786

Table of Contents

Capital Expenditures [a] for the years ended December 31,	2021	2020	2019
Electric Utilities	$ 285,770	$ 288,683	$ 316,687
Gas Utilities	383,320	449,209	512,366
Corporate and Other	10,500	17,500	20,702
Total capital expenditures	$ 679,590	$ 755,392	$ 849,755

(a) Includes accruals for property, plant and equipment as disclosed in the Supplemental Cash Flow Information to the Consolidated Statement of Cash Flows.

	Consolidating Income Statement				
Year ended December 31, 2021	Electric Utilities	Gas Utilities	Corporate	Inter-Company Eliminations	Total
Revenue -					
Contracts with customers	$ 825,404	$ 1,105,430	$ —	$ —	$ 1,930,834
Other revenues	5,336	12,932	—	—	18,268
	830,740	1,118,362	—	—	1,949,102
Inter-company operating revenue -					
Contracts with customers	11,518	6,110	196	(17,824)	—
Other revenues	—	393	356,151	(356,544)	—
	11,518	6,503	356,347	(374,368)	—
Total revenue	842,258	1,124,865	356,347	(374,368)	1,949,102
Fuel, purchased power and cost of natural gas sold	248,018	494,738	96	(918)	741,934
Operations and maintenance, including taxes	260,036	314,810	293,265	(306,325)	561,786
Depreciation, depletion and amortization	131,528	104,160	26,838	(26,573)	235,953
Operating income (loss)	$ 202,676	$ 211,157	$ 36,148	$ (40,552)	$ 409,429
Interest expense, net					(152,404)
Impairment of investment					—
Other income (expense), net					1,404
Income tax benefit (expense)					(7,169)
Net income					251,260
Net income attributable to non-controlling interest					(14,516)
Net income available for common stock					$ 236,744

Year ended December 31, 2020	Consolidating Income Statement Electric Utilities	Gas Utilities	Corporate	Inter-Company Eliminations	Total
Revenue -					
Contracts with customers	$ 721,108	$ 959,696	$ —	$ —	$ 1,680,804
Other revenues	6,175	9,962	— $	—	16,137
	727,283	969,658	—	—	1,696,941
Inter-company operating revenue -					
Contracts with customers	11,574	4,724	167	(16,465)	—
Other revenues	—	288	352,976	(353,264)	—
	11,574	5,012	353,143	(369,729)	—
Total revenue	738,857	974,670	353,143	(369,729)	1,696,941
Fuel, purchased power and cost of natural gas sold	138,572	354,645	83	(896)	492,404
Operations and maintenance, including taxes	265,679	303,577	284,501	(301,980)	551,777
Depreciation, depletion and amortization	123,632	100,559	25,150	(24,884)	224,457
Operating income (loss)	210,974	215,889	43,409	(41,969)	428,303
Interest expense, net					(143,470)
Impairment of investment					(6,859)
Other income (expense), net					(2,293)
Income tax benefit (expense)					(32,918)
Net income					242,763
Net income attributable to non-controlling interest					(15,155)
Net income available for common stock					$ 227,608

Year ended December 31, 2019	Consolidating Income Statement Electric Utilities	Gas Utilities	Corporate	Inter-Company Eliminations	Total
Revenue -					
Contracts with customers	$ 719,205	$ 1,007,187	$ —	$ —	$ 1,726,392
Other revenues	8,124	384	—	—	8,508
	727,329	1,007,571	—	—	1,734,900
Inter-company operating revenue -					
Contracts with customers	12,026	2,459	230	(14,715)	—
Other revenues	—	—	343,974	(343,974)	—
	12,026	2,459	344,204	(358,689)	—
Total revenue	739,355	1,010,030	344,204	(358,689)	1,734,900
Fuel, purchased power and cost of natural gas sold	145,972	425,898	269	(1,310)	570,829
Operations and maintenance, including taxes	259,167	301,844	286,800	(298,902)	548,909
Depreciation, depletion and amortization	116,539	92,317	22,065	(21,801)	209,120
Operating income (loss)	217,677	189,971	35,070	(36,676)	406,042
Interest expense, net					(137,659)
Impairment of investment					(19,741)
Other income (expense), net					(5,740)
Income tax benefit (expense)					(29,580)
Net income					213,322
Net income attributable to non-controlling interest					(14,012)
Net income available for common stock					$ 199,310

(17) SUBSEQUENT EVENTS

Except as described below and in Note 3, there have been no events subsequent to December 31, 2021 which would require recognition in the consolidated financial statements or disclosures.

Winter Storm Uri

On January 27, 2022, Kansas Gas received approval from the KCC for their Winter Storm Uri cost recovery settlement with final rates to be implemented in 2022. See Note 2 for additional information.

Transmission Service Agreements

On January 1, 2022, Colorado Electric entered into a firm point-to-point transmission service agreement with Tri-State Generation and Transmission Association Inc. that provides a maximum of 58 MW of capacity and associated energy. This agreement expires December 31, 2024.

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

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2021. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act, as amended, is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2021, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting is presented on Page 56 of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2022 Annual Meeting of Shareholders, which is incorporated herein by reference. Information about our Executive Officers is reported in Part 1 of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2022 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2022 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2022 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services billed to us by our principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34) is set forth in the Proxy Statement for our 2022 Annual Meeting to Shareholders, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of this report

1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II

2. Schedules

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto. Consolidated valuation and qualifying accounts are detailed within Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

3. Exhibits

Exhibits filed herewithin are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated. Items constituting a board of director or management compensatory plan are designated by a cross (†).

Exhibit Number	Description
2.1	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015).

2.2	First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 10-K for 2015).
2.3	Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015).
3.1	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018).
3.2	Amended and Restated Bylaws of the Registrant dated April 24, 2017 (filed as Exhibit 3 to the Registrant's Form 8-K filed on April 28, 2017).
4.1	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.1.1	First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.1.2	Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009).
4.1.3	Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010).
4.1.4	Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013).
4.1.5	Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016).
4.1.6	Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016).
4.1.7	Seventh Supplemental Indenture dated as of August 17, 2018 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2018).
4.1.8	Eighth Supplemental Indenture dated as of October 3, 2019 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on October 4, 2019).
4.1.9	Ninth Supplemental Indenture dated as of June 17, 2020 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on June 17, 2020).
4.1.10	Tenth Supplemental Indenture dated as of August 26, 2021 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 26, 2021).
4.2	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
4.2.1	First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
4.2.2	Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).
4.2.3	Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014).
4.3.1	First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014).
4.3.2	Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).

4.5	Description of Securities (filed as Exhibit 4.5 to the Registrant's Form 10-K for 2019)
10.1†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001).
10.1.1†	First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002).
10.1.2†	Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008).
10.3.1†	First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).
10.4†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).
10.4.1†	First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2018).
10.5†	Black Hills Corporation Post-2018 Nonqualified Deferred Compensation Plan (filed as Exhibit 10.6 to the Registrant's Form 10-K for 2018).
10.6†	Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005).
10.6.1†	First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008).
10.6.2†	Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010).
10.7*†	Black Hills Corporation Amended and Restated 2015 Omnibus Incentive Plan effective January 26, 2021 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2020)
10.8†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013).
10.9†	Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant's Form 10-K for 2015).
10.10†	Form of Restricted Stock Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2015).
10.11*†	Form of Restricted Stock Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after January 26, 2021. (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2020)
10.12†	Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2015).
10.13†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.14†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2017 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2019).
10.15*†	Form of Short-term Incentive Plan for Officers Award Agreement effective for awards granted on or after January 1, 2021 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2020).
10.16*†	Form of Performance Unit Award Agreement for 2015 Omnibus Incentive Plan effective for awards granted on or after January 1, 2021. (filed as Exhibit 10.17 to the Rigistrant's Form 10-K for 2020)
10.17†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.18†	Change in Control Agreement dated November 15, 2019 between Black Hills Corporation and Linden R. Evans (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2019).
10.19†	Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2019).
10.20†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008).

10.20.1†	First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010).
10.20.2†	Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012).
10.20.3†	Third Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2015 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2014).
10.20.4†	Fourth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2017 (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2016).
10.20.5†	Fifth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2018 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2017).
10.20.6†	Sixth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2019 (filed as Exhibit 10.18 to the Registrant's Form 10-K for 2018).
10.21†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.8 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.22	Equity Distribution Sales Agreement dated August 4, 2020 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on August 4, 2020).
10.23	Fourth Amended and Restated Credit Agreement dated as of July 19, 2021 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 19, 2021).
10.24	Credit Agreement dated as of February 24, 2021 among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8–K filed on February 25, 2021).
10.25	Non-Employee Director Equity Compensation Plan effective January 1, 2022.
10.26	Form of Restricted Stock Unit Award Agreement (Non-Employee Director) effective for awards granted on or after January 1, 2022.
10.27	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.28	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21*	List of Subsidiaries of Black Hills Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95*	Mine Safety and Health Administration Safety Data
101.INS*	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document

101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document
104*	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLACK HILLS CORPORATION

By: /S/ LINDEN R. EVANS
Linden R. Evans, President and Chief Executive Officer

Dated: February 15, 2022

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ STEVEN R. MILLS Steven R. Mills	Director and Chairman	February 15, 2022
/S/ LINDEN R. EVANS Linden R. Evans, President and Chief Executive Officer	Director and Principal Executive Officer	February 15, 2022
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 15, 2022
/S/ BARRY M. GRANGER Barry M. Granger	Director	February 15, 2022
/S/ TONY A. JENSEN Tony A. Jensen	Director	February 15, 2022
/S/ KATHLEEN S. MCALLISTER Kathleen S. McAllister	Director	February 15, 2022
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 15, 2022
/S/ SCOTT M. PROCHAZKA Scott M. Prochazka	Director	February 15, 2022
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 15, 2022
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 15, 2022
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 15, 2022
/S/ JOHN B. VERING John B. Vering	Director	February 15, 2022

BLACK HILLS CORPORATION NON-EMPLOYEE DIRECTOR
EQUITY Compensation Plan
(Effective January 1, 2022)

Article 1 - Purpose

1.1 Purpose. The purpose of the Black Hills Corporation Non-Employee Director Equity Compensation Plan (the "Plan") is to provide non-employee directors on the Board of Directors of Black Hills Corporation with annual equity compensation awards as compensation for Board service and the opportunity to defer settlement of such awards.

1.2 Coordination with the Omnibus Plan. The Plan is established pursuant to Section 21.14 and other applicable provisions of the Black Hills Corporation Amended and Restated 2015 Omnibus Incentive Plan (the "Omnibus Plan"). All Awards under the Plan shall be granted in accordance with all the applicable provisions of the Omnibus Plan. To the extent there is any conflict between the provisions of the Plan and the Omnibus Plan, the Omnibus Plan shall govern. To the extent necessary to comply with applicable laws, anything in the Plan that would materially amend or alter the Omnibus Plan, requiring stockholder approval, shall not be valid and enforced until such stockholder approval is obtained in such a manner and to such a degree as required.

Article II – Definitions

Capitalized terms used herein, but not defined, shall be given meaning as ascribed to them under the Black Hills Corporation 2015 Omnibus Incentive Plan. For the purposes of the Plan, the following terms are defined as set forth below:

2.1 "Account" means the separate bookkeeping account maintained on the books of the Company for each Participant to track the Participant's Awards, and adjustments thereto.

2.2 "Award" means a Restricted Stock Unit award granted to a Participant under the Plan. Awards shall be subject to the terms and conditions of the Plan, the Omnibus Plan, the Award Agreement, and such other terms and conditions as the Committee shall deem desirable.

2.3 "Beneficiary" means the person or persons designated as such under Article VII of the Plan.

2.4 "Board" means the Board of Directors of the Company.

2.5 "Code" means the Internal Revenue Code of 1986, as amended from time to time.

2.6 "Committee" means the Compensation Committee of the Board or any successor committee or subcommittee of the Board or other committee or subcommittee designated by the Board.

2.7 "Company" means Black Hills Corporation, a South Dakota corporation, and its successors.

2.8 "Deferred Stock Unit" means a Restricted Stock Unit that a Participant elected to defer in accordance with Article V.

2.9 "Effective Date" means January 1, 2022.

2.10 "Omnibus Plan" means the Black Hills Corporation Amended and Restated 2015 Omnibus Incentive Plan, as may be amended from time to time, or any successor equity plan applicable to non-employee directors of the board adopted by the Company.

2.11 "Participant" means a Nonemployee Director who receives an Award under the Plan.

2.12 "Plan" means the Black Hills Corporation Non-Employee Director Equity Compensation Plan.

2.13 "Separation from Service" means a "separation from service" from the Company, within the meaning of Code Section 409A, as applicable to the Participant.

2.14 "Stock" means the common stock, par value $1.00 per share, of the Company.

Article III – Participation

3.1 Each Nonemployee Director shall be eligible to become a Participant in accordance with the provisions of the Plan.

3.2 A Participant shall remain a Participant until he or she has received settlement of all Units to which he or she is entitled under the terms of the Plan.

Article IV – Restricted Stock Unit Awards

4.1 Annual Awards. The Board may grant Awards to each Nonemployee Director, for services to the Company, at such timing and in such amounts as determined by the Board.

4.2 Vesting and Forfeiture. Awards will vest over time, as provided in the Award Agreement. Except as otherwise provided in a Participant's Award Agreement, to vest in the Restricted Stock Units, the Participant must remain on the Board with the Company from the grant date through the applicable vesting date for such Award. Any Restricted Stock Unit that does not vest shall immediately be forfeited. Except as otherwise provided in a Participant's Award Agreement, if a Participant ceases to be on the Board for any reason prior to the Scheduled Vesting Date, all unvested Restricted Stock shall immediately be forfeited.

4.3 Settlement of Awards. Unless settlement is deferred by election of the Participant in accordance with Article V, vested Awards will settle in shares of Stock as provided in the Award Agreement. For any vested Awards that have been deferred by election of the Participant under Article V shall settle as provided in Section 5.3.

Article V – Deferred Stock Units

5.1 Deferral Elections.

a. Generally. Prior to the first day of each calendar year beginning on or after January 1, 2022, each Participant may elect to defer payment of 100% of any Participant's Restricted Stock Unit Award that is granted in such calendar year. To be effective, such election must be completed and delivered to the Company prior to the first day of the calendar year in which the service period associated with the Award begins. Any election made under this Section shall become irrevocable as of December 31 of the year prior to the year in which the service period associated with the Restricted Stock Unit Award begins. By way of illustration, a deferral election must be made by December 31, 2021 to defer an Award that is granted to Participant in 2022, for services performed starting in 2022.

b. Election Procedures. An election (or the modification or revocation of an election) must be made in such manner and in accordance with such rules (such as timing of election period, method of electing, etc.) as may be prescribed for this purpose by the Company. In addition, the Company may, in its discretion, allow other deferral elections, to the extent such elections comply with the requirements of Code Section 409A and the applicable Treasury Regulations.

5.2 Vesting. A Deferred Stock Unit shall only be vested if the Participant has become vested under the terms of the associated Award Agreement.

5.3 Settlement. For all Deferred Stock Units, a Participant's Deferred Stock Units will settle in shares of Stock as soon as practicable (but no later than the 15th day of the third calendar month following) the date the Participant ceases to be a Director and experiences a Separation from Service.

Article VI – Accounts

6.1 Accounts Generally. An Account will be established for each Participant. Accounts are for bookkeeping purposes only and the maintenance of Accounts will not require any segregation of assets by the Company. The Company will not have any obligation whatsoever to set aside funds for the Plan or for the benefit of any Participant or Beneficiary, and no Participant or Beneficiary will have any rights to any amounts that may be set aside other than the rights of an unsecured creditor of the Company.

6.2 Adjustments.

a. Dividends. Whenever any cash dividends are declared on the Stock, the Company will credit the Account of each Participant on the date such dividend is paid with a number of additional Restricted Stock Units (or, if an Award is subject to a deferral election under Article V, additional Deferred Stock Units) equal to the result of dividing (i) the product of (x) the total number of Restricted Stock Units (or Deferred Stock Units, if applicable) credited to the Participant's Account on the record date for such dividend and (y) the per share amount of such dividend by (ii) the Fair Market Value of one share of Stock on the date such dividend is paid by the Company to the holders of Stock.

b. Other Adjustments. In the event of any change in the outstanding shares of common stock of the Company, Awards may be adjusted, as provided in the Omnibus Plan.

6.3 Statement of Account. Each Director will be provided Account statements on an annual basis, in such manner as determined by the Company.

Article VII - Beneficiary

7.1 Designation of Beneficiary. A Participant may designate a beneficiary or beneficiaries to receive benefits after the death of the Participant. The designation shall be effective upon filing written notice with the Company on the form provided for that purpose. If more than one beneficiary designation has been filed, the beneficiary or beneficiaries designated in the notice bearing the most recent date will be deemed to be the valid beneficiary or beneficiaries. The Participant shall have the right, without the requirement of approval from any person, to revoke and change beneficiary designations. If no valid beneficiary designation has been made, or if all beneficiaries due before a Participant's entire Account has been distributed, payment of the remaining Account will be made to the Participant's estate.

7.2 Death of Participant. If a Participant dies before receiving settlement of the full balance of the Participant's Account, then the balance of the Participant's vested Account shall be settled in a lump sum settlement in shares of Stock, payable to the Participant's Beneficiary. The lump sum Stock settlement will be made as soon as practicable following the Company's receipt of notification of the Participant's death. However, if the identity of the Beneficiary cannot be determined, or if the Beneficiary cannot be located, payment to the Beneficiary may be delayed to the extent allowed under Code Section 409A and applicable guidance.

Article VIII – Administration

The Plan shall be administered by the Committee, in accordance with the administration provisions of the Omnibus Plan.

For the avoidance of doubt, the ministerial functions of the Plan shall be handled by employees of the Company, in accordance with the rules and regulations established by the Committee.

Article IX – Amendment and Termination

The Board may amend or terminate the Plan at any time in whole or in part; provided, however, that no amendment or termination shall directly or indirectly reduce the balance of Participant's Account held hereunder as of the effective date of such amendment or termination. Notwithstanding the foregoing, the Plan may be amended at any time, without the consent of any Participant (or beneficiary) if necessary or desirable, as determined by the Company, to comply with the requirements, or avoid the application, of Code Section 409A.

A termination of the Plan will not be effective to cause a deferral election in place under the Plan for the applicable year to be modified or discontinued prior to the end of such year, if such modification or discontinuation would violate Code Section 409A. The Board may terminate the Plan and provide for the acceleration and liquidation of Deferred Stock Units remaining due under the Plan pursuant to Treasury Regulations § 1.409A-3(j)(4)(ix). If such a termination and liquidation occurs, all Awards under the Plan will be discontinued as of the termination date established by the Board, and all outstanding Deferred Stock Unit Awards due will be settled at the time specified by the Board as part of the action terminating the Plan and consistent with Treasury Regulations § 1.409A-3(j)(4)(ix).

The Board may terminate the Plan other than pursuant to Treasury Regulations § 1.409A-3(j)(4)(ix). In the event of such other termination, no new deferral elections will be allowed after the end of the calendar year which includes the date of termination, but all Deferred Stock Units under the Plan will be paid at the same time and in the same form as if the termination had not occurred – that is, the termination will not result in any acceleration of any distribution of Deferred Stock Units under the Plan.

Article X - Miscellaneous

10.1 Unfunded Plan. The Plan at all times shall be entirely unfunded and no provision shall at any time be made with respect to segregating any assets of the Company for payment of any benefits hereunder. No Participant, Beneficiary or any other person shall have any interest in any particular assets of the Company by reason of the right to receive a benefit under the Plan and any such Participant, Beneficiary or other person shall have only the rights of a general unsecured creditor of the Company with respect to any rights under the Plan. All payments hereunder shall be made by the Company from its general assets at the time and in the manner provided for in the Plan. Nothing contained in the Plan shall constitute a guaranty by the Company or any other person or entity that the assets of the Company will be sufficient to pay any benefit hereunder. Notwithstanding the foregoing, however, the Company may, in its sole discretion, place assets in a trust that may be used to meet the Company's obligations under the Plan and any right of a Participant to any benefit payment under the Plan shall be reduced by any payment received by the Participant from the trustee under such a trust. In the event such trust is established, the assets of such trust shall be available to the general creditors of the Company in the event of insolvency or bankruptcy of the Company (a "rabbi trust").

10.2 Non-Alienation of Benefits. Neither a Participant nor any other person shall have any rights to sell, assign, transfer, pledge, anticipate, or otherwise encumber the amounts, if any, payable under the Plan to the Participant or any other person. Any attempted sale, assignment, transfer or pledge shall be null and void and without any legal effect. No part of the amounts payable under the Plan shall be subject to seizure or sequestration for the payment of any debts, judgments, alimony or separate maintenance owed by a Participant or any other person, nor be transferable by operation of law in the event of a Participant's or any other person's bankruptcy or insolvency.

10.3 Code Section 409A. For any Award that the settlement of such Award is deferred by election of the Participant in accordance with Article V, this Plan is subject to Code Section 409A and is intended to be maintained in compliance with Code Section 409A and the regulations thereunder applicable to nonqualified deferred compensation plans. To the extent any provision of this Plan applicable to a deferred Award does not satisfy the requirements of Code Section 409A or any regulations or other guidance issued by the Treasury Department or the Internal Revenue Service under Code Section 409A, such provision will be applied in a manner consistent with such requirements, regulations or guidance, notwithstanding any provision of the Plan to the contrary, and to the extent not prohibited by Code Section 409A, the provisions of the Plan and the rights of Participants and Beneficiaries hereunder shall be deemed to have been modified accordingly. Each payment and benefit hereunder shall constitute a “separately identified” amount within the meaning of Treasury Regulation §1.409A-2(b)(2), to the extent applicable. The Committee, in its sole discretion shall determine the requirements of Code Section 409A that are applicable to the Plan and shall interpret the terms of the Plan in a manner consistent therewith. Under no circumstances, however, shall the Company or any affiliate or any of its or their employees, officers, directors, service providers or agents have any liability to any person for any taxes, penalties or interest due on amounts paid or payable under the Plan, including any taxes, penalties or interest imposed under Code Section 409A. For any Award that is not deferred in accordance with Article V, the Plan is intended to be exempt from Code Section 409A as a short-term deferral, and is to be interpreted accordingly.

10.4 Severability. If any term or provision of this Plan or the application thereof to any person or circumstances shall, to any extent, be invalid or unenforceable, then the remainder of the Plan, or the application of such term or provision to persons or circumstances other than those as to which it was held invalid or unenforceable, shall not be affected thereby, and each term and provision hereof shall be valid and enforceable to the fullest extent permitted by applicable law.

10.5 Successors in Interest. The obligation of the Company under the Plan shall be binding upon any successor or successors of the Company, whether by merger, consolidation, sale of assets or otherwise, and for this purpose reference herein to the Company shall be deemed to include any such successor or successors.

10.6 Governing Law. The validity, construction, interpretation, administration and effect of the Plan and of its rules and regulations, and rights relating to the Plan, shall be determined solely in accordance with the laws of the State of South Dakota, without regard to the conflicts of laws provisions thereof.

10.7 No Stockholder Rights. Neither the Participant or any other person shall have any rights as a stockholder of the Company with respect to the Restricted Stock Units or Deferred Stock Units credited to the Participant’s Account until the shares of Stock are issued to the Participant (or the Beneficiary of the Participant).

10.8 No Contract. Neither the action of the Company in establishing the Plan nor any action taken by it or by the Committee under this Plan (or any award thereunder) shall be construed as giving any Participant the right to be retained as a Director or other service provider of the Company.

BLACK HILLS CORPORATION NON-EMPLOYEE DIRECTOR
EQUITY COMPENSATION PLAN
UNDER THE BLACK HILLS CORPORATION
AMENDED AND RESTATED 2015 omnibus INCENTIVE PLAN

Restricted Stock Unit Award Agreement (Non-Employee Director)

Black Hills Corporation (the “Company”), pursuant to its Non-Employee Director Equity Compensation Plan (the “Non-Employee Director Equity Plan”) under its Amended and Restated 2015 Omnibus Incentive Plan (the “Omnibus Plan”), hereby grants an award of Restricted Stock Units to you, the Participant named below. The terms and conditions of this Award are set forth in this Restricted Stock Unit Award Agreement (the “Agreement”), consisting of this cover page and the Terms and Conditions on the following pages, and in the Omnibus Plan document and the Non-Employee Director Equity Plan document, a copy of both documents which has been made available to you. Any capitalized term that is used but not defined in this Agreement shall have the meaning assigned to it in the Omnibus Plan or Non-Employee Director Equity Plan, as they currently exist or as they may be amended in the future.

Name of Participant:
Number of Restricted Stock Units:
Grant Date:
Scheduled Vesting Date: Earlier of date of the Company’s Shareholder Meeting in ____ or May 1, ___

By signing below or otherwise evidencing your acceptance of this Agreement in a manner approved by the Company, you agree to all of the terms and conditions contained in this Agreement, the Omnibus Plan and Non-Employee Director Equity Plan. You acknowledge that you have reviewed these documents.

PARTICIPANT: BLACK HILLS CORPORATION

By:

Title: VP – Governance, Corporate Secretary & Deputy
General Counsel

BLACK HILLS CORPORATION NON-EMPLOYEE DIRECTOR
EQUITY COMPENSATION PLAN
UNDER THE BLACK HILLS CORPORATION
AMENDED AND RESTATED 2015 omnibus INCENTIVE PLAN
Restricted Stock Unit Award Agreement (Non-Employee Director)

Terms and Conditions

1. **Grant of Restricted Stock Units**. The Company hereby confirms the grant to you, as of the Grant Date and subject to the terms and conditions in this Agreement, the Omnibus Plan and the Non-Employee Director Equity Plan, of the number of Restricted Stock Units specified on the cover page of this Agreement (the "Units"). Each Unit represents the right to receive one share of the Company's Stock (each, a "Share"). Prior to their settlement or forfeiture in accordance with the terms of this Agreement, the Units granted to you will be credited to an account in your name maintained by the Company. This account shall be unfunded and maintained for book-keeping purposes only, with the Units simply representing an unfunded and unsecured contingent obligation of the Company.

2. **Restrictions Applicable to Units**. Neither this Award nor the Units subject to this Award may be sold, assigned, transferred, exchanged or encumbered, voluntarily or involuntarily, other than a transfer upon your death in accordance with your will, by the laws of descent and distribution or pursuant to a beneficiary designation submitted in accordance with the Plan. Following any such transfer, this Award shall continue to be subject to the same terms and conditions that were applicable to this Award immediately prior to its transfer. Any attempted transfer in violation of this Section 2 shall be void and without effect. The Units and your right to receive Shares in settlement of the Units under this Agreement shall be subject to forfeiture as provided in Section 5 until satisfaction of the vesting conditions set forth in Section 4.

3. **No Shareholder Rights**. The Units subject to this Award do not entitle you to any rights of a holder of the Company's common stock. You will not have any of the rights of a shareholder of the Company in connection with the grant of Units subject to this Agreement unless and until Shares are issued to you upon settlement of the Units as provided in Section 6.

4. **Vesting of Units**. For purposes of this Agreement, "Vesting Date" means any date, including the Scheduled Vesting Date specified on the cover page of this Agreement, on which Units subject to this Agreement vest as provided in this Section 4. Notwithstanding the vesting and subsequent settlement of this Award, the Award and any Share issuances or payments made hereunder shall remain subject to the provisions of Section 21.1 of the Omnibus Plan.

   a. Scheduled Vesting. If you remain a Director continuously from the Grant Date specified on the cover page of this Agreement, then the Units will vest on the Scheduled Vesting Date.

   b. Accelerated Vesting. The vesting of outstanding Units will be accelerated under the circumstances provided below:

      1. *Death or Disability*. If you cease to be a Director prior to the Scheduled Vesting Date due to your death or Disability, then all of the unvested Units shall vest as of such termination date. Disability for this purpose means that the Director is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

2. *Change of Control*. If a Change of Control occurs while you are a Director and prior to the Scheduled Vesting Date, then all of the unvested Units shall vest as of the date of the consummation of such Change of Control.

5. **Forfeiture**. Except as otherwise provided in accordance with Section 4 above or under the terms of the Non-Employee Director Equity Plan, if you cease to be a Director, you will forfeit all unvested Units.

6. **Settlement of Units**.

a. Unless you have elected to defer settlement of the Units, after any Units vest pursuant to Section 4, the Company shall, as soon as practicable (but no later than the 15th day of the third calendar month following the Vesting Date), cause to be issued and delivered to you (or to your personal representative or your designated beneficiary or estate in the event of your death, as applicable) one Share in payment and settlement of each vested Unit. Delivery of the Shares shall be effected by the issuance of a stock certificate to you, by an appropriate entry in the stock register maintained by the Company's transfer agent with a notice of issuance provided to you, or by the electronic delivery of the Shares to a brokerage account you designate, and shall be subject to the tax provisions of Section 8, to the extent applicable, and compliance with all applicable legal requirements as provided in the Omnibus Plan, and shall be in complete satisfaction and settlement of such vested Units. If the Units that vest include a fractional Unit, the Company shall round the number of vested Units to the nearest whole Unit prior to issuance of Shares as provided herein.

b. If you have elected to defer the settlement of the Units ("Deferred Units") pursuant to the terms of the Non-Employee Director Equity Plan, after any Deferred Units vest pursuant to Section 4, the settlement of such Deferred Units shall be governed by the terms of the Non-Employee Director Equity Plan and your related deferral election.

7. **Dividend Equivalents**. If the Company pays cash dividends on its Shares while any Units subject to this Agreement are outstanding, then the Company shall credit, as of each dividend payment date, with a number of additional Units (the "Dividend Units") equal to the result of dividing (i) the product of (x) the total number of Restricted Stock Units credited to your Account on the record date for such dividend and (y) the per share amount of such dividend by (ii) the Fair Market Value of one Share on the date such dividend is paid by the Company to the holder of Shares. Your right to receive such accrued Dividend Units shall vest, and the Dividend Units shall be settled, to the same extent and at the same time as the underlying Units to which the Dividend Units relate vest and are settled, as provided in Sections 4 and 6 of this Agreement. Any Dividend Units accrued on Units that are forfeited in accordance with this Agreement shall also be forfeited.

8. **Tax Consequences**. No Shares will be delivered to you in settlement of vested Units unless you have made arrangements acceptable to the Company for payment of any federal, state, local or foreign taxes that may be due as a result of the delivery of the Shares.

9. **Notices**. Every notice or other communication relating to this Agreement shall be in writing and shall be mailed to or delivered (including electronically) to the party for whom it is intended at such address as may from time to time be designated by it in a notice mailed or delivered to the other party as herein provided. Unless and until some other address is so designated, all notices or communications by you to the Company shall be mailed or delivered to the Company, to the attention of its Corporate Secretary, at its office at 7001 Mt. Rushmore Road, Rapid City, SD 57702, amy.koenig@blackhillscorp.com, and all notices or communications by the Company to you may be given to you personally or may be mailed or, if you are still a Director, emailed to you at the address indicated in the Company's records as your most recent mailing or email address.

10. **Additional Provisions**.

a. No Right to Continued Service. This Agreement does not give you a right to continue as a Director or other service provider with the Company or any Affiliate, regardless of the effect it may have upon you under this Agreement.

b. Governing Plan Document. This Agreement and the Award are subject to all the provisions of the Omnibus Plan, the Non-Employee Director Equity Plan, and to all interpretations, rules and regulations which may, from time to time, be adopted and promulgated by the Committee pursuant to the Omnibus Plan and the Non-Employee Director Equity Plan. If there is any conflict between the provisions of this Agreement and the Omnibus Plan or Non-Employee Director Equity Plan, the provisions of the Omnibus Plan or Non-Employee Director Equity Plan will govern.

c. Governing Law. This Agreement, the parties' performance hereunder, and the relationship between them shall be governed by, construed, and enforced in accordance with the laws of the State of South Dakota, without giving effect to the choice of law principles thereof. The parties agree that any action relating to or arising out of this Agreement shall take place exclusively in the State of South Dakota, and you consent to the jurisdiction of the federal and/or state courts in South Dakota. You further consent to personal jurisdiction and venue in both such courts and to service of process by United States Mail or express courier service in any such action.

d. Severability. The provisions of this Agreement shall be severable and if any provision of this Agreement is found by any court to be unenforceable, in whole or in part, the remainder of this Agreement shall nevertheless be enforceable and binding on the parties. You also agree that any trier of fact may modify any invalid, overbroad or unenforceable provision of this Agreement so that such provision, as modified, is valid and enforceable under applicable law.

e. Binding Effect. This Agreement will be binding in all respects on your heirs, representatives, successors and assigns, and on the successors and assigns of the Company.

f. Section 409A of the Code. Except to the extent Participant has elected to defer the Units pursuant to the terms of the Non-Employee Director Equity Plan and his or her related deferral election form, the award of Units as provided in this Agreement and any issuance of Shares or payment pursuant to this Agreement are intended to be exempt from Section 409A of the Code under the short-term deferral exception specified in Treas. Reg. § 1.409A-l(b)(4).

g. Electronic Delivery and Acceptance. The Company may deliver any documents related to this Restricted Stock Unit Award by electronic means and request your acceptance of this Agreement by electronic means. You hereby consent to receive all applicable documentation by electronic delivery and to participate in the Omnibus Plan and Non-Employee Director Equity Plan through an on-line (and/or voice activated) system established and maintained by the Company or, if appliable, the Company's third-party stock plan administrator.

By signing the cover page of this Agreement or otherwise accepting this Agreement in a manner approved by the Company, you agree to all the terms and conditions described above, in the Omnibus Plan document and the Non-Employee Director Equity Plan document.

Exhibit 21

BLACK HILLS CORPORATION SUBSIDIARIES
December 31, 2021

	Subsidiary Name	State of Origin
1.	Black Hills Colorado Electric, LLC *	Delaware
2.	Black Hills Colorado Gas, Inc. *	Colorado
3.	Black Hills Colorado IPP, LLC *	South Dakota
4.	Black Hills Colorado Wind, LLC	Delaware
5.	Black Hills Electric Generation, LLC *	South Dakota
6.	Black Hills Energy Arkansas, Inc. *	Arkansas
7.	Black Hills Energy Services Company *	Colorado
8.	Black Hills Exploration and Production, Inc. *	Wyoming
9.	Black Hills Gas, Inc.	Delaware
10.	Black Hills Gas, LLC	Delaware
12.	Black Hills Gas Holdings, LLC	Delaware
13.	Black Hills Gas Parent Holdings II, Inc.	Delaware
14.	Black Hills Gas Resources, Inc. *	Colorado
15.	Black Hills/Iowa Gas Utility Company, LLC *	Delaware
16.	Black Hills/Kansas Gas Utility Company, LLC *	Kansas
17.	Black Hills Nebraska Gas, LLC *	Delaware
18.	Black Hills Non-regulated Holdings, LLC	South Dakota
19.	Black Hills Plateau Production, LLC *	Delaware
20.	Black Hills Power, Inc. *	South Dakota
21.	Black Hills Service Company, LLC *	South Dakota
22.	Black Hills Shoshone Pipeline, LLC *	Wyoming
23.	Black Hills Utility Holdings, Inc. *	South Dakota
24.	Black Hills Wyoming, LLC	Wyoming
25.	Black Hills Wyoming Gas, LLC *	Wyoming
26.	Cheyenne Light, Fuel and Power Company *	Wyoming
27.	Mallon Oil Company, Sucursal Costa Rica	Costa Rica
28.	N780BH, LLC	South Dakota
29.	Northern Iowa Windpower, LLC	Delaware
30.	Rocky Mountain Natural Gas LLC *	Colorado
31.	Wyodak Resources Development Corp. *	Delaware

* doing business as **Black Hills Energy**

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-240320 and 333-240319 on Form S-3 and Registration Statement Nos. 333-170451, 333-217679, 333-170448, 333-170452, and 333-203714 on Form S-8 of our reports dated February 15, 2022, relating to the consolidated financial statements of Black Hills Corporation and subsidiaries (the “Company”), and the effectiveness of the Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Black Hills Corporation for the year ended December 31, 2021.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 15, 2022

Exhibit 31.1

CERTIFICATION

I, Linden R. Evans, certify that:

1. I have reviewed this Annual Report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 15, 2022

/S/ LINDEN R. EVANS

Linden R. Evans

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard W. Kinzley, certify that:

1. I have reviewed this Annual Report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 15, 2022

/S/ RICHARD W. KINZLEY

Richard W. Kinzley

Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the "Company") on Form 10-K for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Linden R. Evans, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 15, 2022

/S/ LINDEN R. EVANS
Linden R. Evans
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Richard W. Kinzley, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 15, 2022

/S/ RICHARD W. KINZLEY
Richard W. Kinzley
Senior Vice President and Chief Financial Officer

Exhibit 95

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included below.

Mine Safety and Health Administration Safety Data

Safety is a core value at Black Hills Corporation and at each of its subsidiary operations. We have in place a comprehensive safety program that includes extensive health and safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

Under the Dodd-Frank Act, each operator of a coal or other mine is required to include certain mine safety results in its periodic reports filed with the SEC. Our mining operation, consisting of Wyodak Coal Mine, is subject to regulation by the federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). Below we present the following information regarding certain mining safety and health matters for the twelve month period ended December 31, 2021. In evaluating this information, consideration should be given to factors such as: (i) the number of citations and orders will vary depending on the size of the coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process, are often reduced in severity and amount, and are sometimes dismissed. The information presented includes:

- Total number of violations of mandatory health and safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which we have received a citation from MSHA;
- Total number of orders issued under section 104(b) of the Mine Act;
- Total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health and safety standards under section 104(d) of the Mine Act;
- Total number of imminent danger orders issued under section 107(a) of the Mine Act; and
- Total dollar value of proposed assessments from MSHA under the Mine Act.

The table below sets forth the total number of citations and/or orders issued by MSHA to WRDC under the indicated provisions of the Mine Act, together with the total dollar value of proposed MSHA assessments received during the twelve months ended December 31, 2021 and legal actions pending before the Federal Mine Safety and Health Review Commission, together with the Administrative Law Judges thereof, for WRDC, our only mining complex. All citations were abated within 24 hours of issue.

Mine/MSHA Identification Number	Mine Act Section 104 S&S Citations issued during twelve months ended December 31 2021	Mine Act Section 104(b) Orders (#)	Mine Act Section 104(d) Citations and Orders (#)	Mine Act Section 110(b) (2) Violations (#)	Mine Act Section 107(a) Imminent Danger Orders (#)	Total Dollar Value of Proposed MSHA Assessments (a)	Total Number of Mining Related Fatalities (#)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Wyodak Coal Mine - 4800083	—	—	—	—	—	$ 396	—	No	—	—	—

(a) The types of proceedings by class: (1) Contests of citations and orders – none; (2) contests of proposed penalties – none; (3) complaints for compensation – none; (4) complaints of discharge, discrimination or interference under Section 105 of the Mine Act – none; (5) applications for temporary relief – none; and (6) appeals of judges' decisions or orders to the FMSHRC – none.