UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 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

Former name, former address, and former fiscal year if changed since last report
NONE

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 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	x	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. o

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

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock of $1.00 par value	BKH	New York Stock Exchange

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

Class	Outstanding at July 31, 2021
Common stock, $1.00 par value	63,480,270 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
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).
ASC	Accounting Standards Codification
ASU	Accounting Standards Update 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
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
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.
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 for the unbundling of the commodity service from the distribution delivery service.
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).
Consolidated Indebtedness to Capitalization Ratio	Any indebtedness outstanding at such time, divided by capital at such time. Capital being consolidated net worth (excluding noncontrolling interest) plus consolidated indebtedness (including letters of credit and certain guarantees issued) as defined within the current Revolving Credit Facility.
Cooling Degree Day (CDD)	A cooling degree day is equivalent to each degree that the average of the high and low temperatures 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 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 and Wyoming Electric, 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

CVA	Credit Valuation Adjustment
Dth	Dekatherm. A unit of energy equal to 10 therms or approximately one million British thermal units (MMBtu)
Economy Energy	Purchased energy that costs less than that produced with the utilities’ owned generation.
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
GHG	Greenhouse Gases
Heating Degree Day (HDD)	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 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.
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
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
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
LIBOR	London Interbank Offered Rate
MMBtu	Million British thermal units
Moody’s	Moody’s Investors Service, Inc.
MW	Megawatts
MWh	Megawatt-hours
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.
NOL	Net Operating Loss
NPSC	Nebraska Public Service Commission
OCI	Other Comprehensive Income
PPA	Power Purchase Agreement
PSA	Power Sales Agreement
Pueblo Airport Generation	The 420 MW combined cycle gas-fired power generation plants jointly owned by Colorado Electric (220 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.
Renewable Advantage	A 200 MW solar facility project to be constructed in Pueblo County, Colorado. The project aims to lower customer energy costs and provide economic and environmental benefits to Colorado Electric’s customers and communities. This project, which was approved by the CPUC in September 2020, will be owned by a third-party renewable energy developer with Colorado Electric purchasing all of the energy generated at the facility under the terms of a 15-year PPA. The project is expected to be placed in service in 2023.
Renewable Ready	Voluntary renewable energy subscription program for large commercial, industrial and governmental agency customers in South Dakota and Wyoming.
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.
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.
S&P	Standard and Poor’s, a division of The McGraw-Hill Companies, Inc.
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).
SSIR	System Safety and Integrity Rider
TCJA	Tax Cuts and Jobs Act
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.
Utilities	Black Hills’ Electric and Gas Utilities
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 extremely cold temperatures in the central United States and led to unprecedented fluctuations in customer demand and market pricing for natural gas and energy.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corporation, 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 power plant 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 110 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 362 MW mine-mouth, coal-fired generation facility near Gillette, Wyoming, 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 and wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Wyoming (doing business as Black Hills Energy).

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q 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 2 - 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 the statement was made. 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 was 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 described in our 2020 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2020 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
	(in thousands, except per share amounts)			
Revenue	$ 372,572	$ 326,914	$ 1,006,004	$ 863,964
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	108,474	71,629	401,621	259,508
Operations and maintenance	123,245	117,308	252,924	242,774
Depreciation, depletion and amortization	58,443	56,663	115,712	113,065
Taxes - property and production	15,144	14,381	30,166	28,499
Total operating expenses	305,306	259,981	800,423	643,846
Operating income	67,266	66,933	205,581	220,118
Other income (expense):				
Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	(38,669)	(35,765)	(76,494)	(71,546)
Interest income	467	220	692	548
Impairment of investment	—	—	—	(6,859)
Other income (expense), net	(191)	(1,863)	75	490
Total other income (expense)	(38,393)	(37,408)	(75,727)	(77,367)
Income before income taxes	28,873	29,525	129,854	142,751
Income tax (expense)	(586)	(4,831)	(1,080)	(20,833)
Net income	28,287	24,694	128,774	121,918
Net income attributable to noncontrolling interest	(3,126)	(3,728)	(7,297)	(7,778)
Net income available for common stock	$ 25,161	$ 20,966	$ 121,477	$ 114,140
Earnings per share of common stock:				
Earnings per share, Basic	$ 0.40	$ 0.34	$ 1.94	$ 1.84
Earnings per share, Diluted	$ 0.40	$ 0.33	$ 1.93	$ 1.83
Weighted average common shares outstanding:				
Basic	62,867	62,573	62,751	62,175
Diluted	62,918	62,617	62,817	62,230

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
	(in thousands)			
Net income	$ 28,287	$ 24,694	$ 128,774	$ 121,918
Other comprehensive income (loss), net of tax:				
Benefit plan liability adjustments - net gain (net of tax of $0, $0, $0 and $(17), respectively)	—	—	—	55
Reclassification adjustments of benefit plan liability - prior service cost (net of tax of $6, $6, $15 and $13, respectively)	(18)	(19)	(34)	(42)
Reclassification adjustments of benefit plan liability - net loss (net of tax of $(157), $(182), $(374) and $(277), respectively)	440	415	821	917
Derivative instruments designated as cash flow hedges:				
Reclassification of net realized losses on settled/amortized interest rate swaps (net of tax of $(150), $(170), $(340) and $(340), respectively)	563	543	1,086	1,086
Net unrealized gains (losses) on commodity derivatives (net of tax of $(304), $14, $(339) and $68, respectively)	939	(45)	1,046	(220)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $14, $(16), $6 and $(131), respectively)	(42)	54	(19)	425
Other comprehensive income, net of tax	1,882	948	2,900	2,221
Comprehensive income	30,169	25,642	131,674	124,139
Less: comprehensive income attributable to noncontrolling interest	(3,126)	(3,728)	(7,297)	(7,778)
Comprehensive income available for common stock	$ 27,043	$ 21,914	$ 124,377	$ 116,361

See Note 9 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of	
	June 30, 2021	December 31, 2020
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,175	$ 6,356
Restricted cash and equivalents	4,559	4,383
Accounts receivable, net	189,437	265,961
Materials, supplies and fuel	114,089	117,400
Derivative assets, current	3,925	1,848
Income tax receivable, net	17,573	19,446
Regulatory assets, current	218,628	51,676
Other current assets	22,353	26,221
Total current assets	571,739	493,291
Property, plant and equipment	7,558,204	7,305,530
Less: accumulated depreciation and depletion	(1,361,453)	(1,285,816)
Total property, plant and equipment, net	6,196,751	6,019,714
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	11,356	11,944
Regulatory assets, non-current	617,781	226,582
Other assets, non-current	40,971	37,801
Total other assets, non-current	1,969,562	1,575,781
TOTAL ASSETS	$ 8,738,052	$ 8,088,786

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)

(unaudited)	As of	
	June 30, 2021	December 31, 2020
	(in thousands, except share amounts)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 133,354	$ 183,340
Accrued liabilities	219,022	243,612
Derivative liabilities, current	5,178	2,044
Regulatory liabilities, current	36,124	25,061
Notes payable	829,850	234,040
Current maturities of long-term debt	7,000	8,436
Total current liabilities	1,230,528	696,533
Long-term debt, net of current maturities	3,530,216	3,528,100
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	436,495	408,624
Regulatory liabilities, non-current	497,608	507,659
Benefit plan liabilities	151,290	150,556
Other deferred credits and other liabilities	133,021	134,667
Total deferred credits and other liabilities	1,218,414	1,201,506
Commitments, contingencies and guarantees (Note 3)		
Equity:		
Stockholders' equity —		
Common stock $1 par value; 100,000,000 shares authorized; issued 63,526,913 and 62,827,179 shares, respectively	63,527	62,827
Additional paid-in capital	1,701,825	1,657,285
Retained earnings	921,122	870,738
Treasury stock, at cost – 46,528 and 32,492 shares, respectively	(2,988)	(2,119)
Accumulated other comprehensive income (loss)	(24,446)	(27,346)
Total stockholders' equity	2,659,040	2,561,385
Noncontrolling interest	99,854	101,262
Total equity	2,758,894	2,662,647
TOTAL LIABILITIES AND TOTAL EQUITY	$ 8,738,052	$ 8,088,786

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Operating activities:	(in thousands)	
Net income	$ 128,774	$ 121,918
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	115,712	113,065
Deferred financing cost amortization	4,381	4,246
Impairment of investment	—	6,859
Stock compensation	5,044	1,113
Deferred income taxes	692	26,401
Employee benefit plans	4,934	5,656
Other adjustments, net	10,495	3,679
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	3,974	7,503
Accounts receivable and other current assets	88,513	73,302
Accounts payable and other current liabilities	(59,640)	(63,085)
Regulatory assets	(540,709)	21,887
Regulatory liabilities	(9,509)	314
Contributions to defined benefit pension plans	—	(12,700)
Other operating activities, net	(2,834)	(1,152)
Net cash provided by (used in) operating activities	(250,173)	309,006
Investing activities:		
Property, plant and equipment additions	(319,476)	(348,313)
Other investing activities	9,739	(1,412)
Net cash (used in) investing activities	(309,737)	(349,725)
Financing activities:		
Dividends paid on common stock	(71,092)	(66,440)
Common stock issued	40,037	99,435
Term loan - borrowings	800,000	—
Term loan - repayments	(200,000)	—
Net payments of Revolving Credit Facility and CP Program	(4,190)	(349,500)
Long-term debt - issuances	—	400,000
Long-term debt - repayments	(1,436)	(5,727)
Distributions to noncontrolling interest	(8,705)	(8,520)
Other financing activities	291	(6,474)
Net cash provided by financing activities	554,905	62,774
Net change in cash, restricted cash and cash equivalents	(5,005)	22,055
Cash, restricted cash and cash equivalents at beginning of period	10,739	13,658
Cash, restricted cash and cash equivalents at end of period	$ 5,734	$ 35,713
Supplemental cash flow information:		
Cash (paid) refunded during the period:		
Interest, net of amounts capitalized	$ (71,825)	$ (67,449)
Income taxes	1,486	1,896
Non-cash investing and financing activities:		
Accrued property, plant and equipment purchases at June 30	54,448	59,916

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(unaudited)	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
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	—	—	—	—	—	96,316	—	4,171	100,487
Other comprehensive income, net of tax	—	—	—	—	—	—	1,018	—	1,018
Dividends on common stock ($0.565 per share)	—	—	—	—	—	(35,514)	—	—	(35,514)
Share-based compensation	82,794	83	7,448	(445)	1,672	—	—	—	1,310
Other	—	—	—	—	—	(2)	—	—	(2)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(4,644)	(4,644)
March 31, 2021	62,909,973	$ 62,910	39,940	$ (2,564)	$ 1,658,957	$ 931,538	$ (26,328)	$ 100,789	$ 2,725,302
Net income	—	—	—	—	—	25,161	—	3,126	28,287
Other comprehensive income, net of tax	—	—	—	—	—	—	1,882	—	1,882
Dividends on common stock ($0.565 per share)	—	—	—	—	—	(35,578)	—	—	(35,578)
Share-based compensation	20,905	21	6,588	(424)	3,698	—	—	—	3,295
Issuance of common stock	596,035	596	—	—	39,636	—	—	—	40,232
Issuance costs	—	—	—	—	(466)	—	—	—	(466)
Other	—	—	—	—	—	1	—	—	1
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(4,061)	(4,061)
June 30, 2021	63,526,913	$ 63,527	46,528	$ (2,988)	$ 1,701,825	$ 921,122	$ (24,446)	$ 99,854	$ 2,758,894

	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
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	—	—	—	—	—	93,174	—	4,050	97,224
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	1,273	—	1,273
Dividends on common stock ($0.535 per share)	—	—	—	—	—	(32,902)	—	—	(32,902)
Share-based compensation	69,378	69	20,700	(1,658)	2,263	—	—	—	674
Issuance of common stock	1,222,942	1,223	—	—	98,777	—	—	—	100,000
Issuance costs	—	—	—	—	(967)	—	—	—	(967)
Implementation of ASU 2016-13 Financial Instruments - Credit Losses	—	—	—	—	—	(207)	—	—	(207)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(4,741)	(4,741)
March 31, 2020	62,772,978	$ 62,773	24,656	$ (1,925)	$ 1,652,861	$ 838,841	$ (29,382)	$ 101,255	$ 2,624,423
Net income	—	—	—	—	—	20,966	—	3,728	24,694
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	948	—	948
Dividends on common stock ($0.535 per share)	—	—	—	—	—	(33,538)	—	—	(33,538)
Share-based compensation	18	—	1,743	46	1,781	—	—	—	1,827
Issuance costs	—	—	—	—	(79)	—	—	—	(79)
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(3,779)	(3,779)
June 30, 2020	62,772,996	$ 62,773	26,399	$ (1,879)	$ 1,654,563	$ 826,269	$ (28,434)	$ 101,204	$ 2,614,496

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company’s 2020 Annual Report on Form 10-K)

(1) Management’s Statement

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the “Company”, “us”, “we” or “our”), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes included in our 2020 Annual Report on Form 10-K.

Segment Reporting

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation and Mining. Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Use of Estimates and Basis of Presentation

The information furnished in the accompanying Condensed Consolidated Financial Statements reflects certain estimates required and all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the June 30, 2021, December 31, 2020 and June 30, 2020 financial information. Certain lines of business in which we operate are highly seasonal, and our interim results of operations are not necessarily indicative of the results of operations to be expected for an entire year.

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 the 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 Condensed 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 Condensed 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 three and six months ended June 30, 2021, there were no material adverse impacts on the Company’s results of operations.

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 whether 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 (in thousands):

	As of June 30, 2021	As of December 31, 2020
Regulatory assets		
Winter Storm Uri [a]	$ 541,389	$ —
Deferred energy and fuel cost adjustments [b]	57,715	39,035
Deferred gas cost adjustments [b]	676	3,200
Gas price derivatives [b]	145	2,226
Deferred taxes on AFUDC [c]	7,479	7,491
Employee benefit plans and related deferred taxes [d]	116,003	116,598
Environmental [b]	1,410	1,413
Loss on reacquired debt [b]	21,914	22,864
Deferred taxes on flow through accounting [d]	55,034	47,515
Decommissioning costs [b]	7,205	8,988
Gas supply contract termination [b]	—	2,524
Other regulatory assets [b]	27,439	26,404
Total regulatory assets	836,409	278,258
Less current regulatory assets	(218,628)	(51,676)
Regulatory assets, non-current	$ 617,781	$ 226,582
Regulatory liabilities		
Deferred energy and gas costs [b]	$ 28,261	$ 13,253
Employee benefit plan costs and related deferred taxes [d]	39,542	40,256
Cost of removal [b]	179,968	172,902
Excess deferred income taxes [d]	268,604	285,259
Other regulatory liabilities [d]	17,357	21,050
Total regulatory liabilities	533,732	532,720
Less current regulatory liabilities	(36,124)	(25,061)
Regulatory liabilities, non-current	$ 497,608	$ 507,659

(a) Timing of Winter Storm Uri incremental cost recovery and associated carrying costs are subject to pending applications with our utility commissions. See further information below.
(b) Recovery of costs, but we are not allowed a rate of return.
(c) In addition to recovery of costs, we are allowed a rate of return.
(d) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

Regulatory Activity

Except as discussed below, there have been no other significant changes to our Regulatory Matters from those previously disclosed in Note 2 of the Notes to the Consolidated Financial Statements in our 2020 Annual Report on Form 10-K.

Winter Storm Uri

In February 2021, a prolonged period of historic cold temperatures across the central United States, which 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.

In the first quarter of 2021, $559 million of incremental costs from Winter Storm Uri were recorded to a regulatory asset. Our Utilities submitted cost recovery applications in our state jurisdictions seeking to recover $546 million in total of these incremental costs through separate tracking mechanisms over a weighted-average recovery period of 3.7 years. These incremental cost estimates are subject to adjustments as final decisions are issued by the respective utility commissions. As part of these applications, we seek approval to recover carrying costs. We are also seeking recovery of $13 million of previously disclosed Winter Storm Uri incremental costs through our existing regulatory mechanisms.

In the second quarter of 2021, Nebraska Gas and South Dakota Electric received commission approval on their Winter Storm Uri cost recovery applications. Additionally, Arkansas Gas and Iowa Gas received approval for interim recovery subject to a final decision on carrying costs and recovery periods at a later date. For the three and six months ended June 30, 2021, our Utilities recovered $4.6 million of Winter Storm Uri incremental and carrying costs from customers.

TCJA

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 three and six months ended June 30, 2021.

Colorado Gas

Rate Review

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. The rate review requests $14.6 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 9.95%. The request seeks to implement new rates in the first quarter of 2022.

On September 11, 2020, in accordance with the final Order from an earlier rate review filed 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 that will recover safety and integrity focused investments in its system for three years. 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. Additionally, Iowa Gas is seeking to implement a five year SSIR that would recover safety and integrity focused investments. The rate review requests shifting $2.2 million of rider revenue to base rates and $8.3 million in additional new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 10.15%. Iowa statute allows implementation of interim rates 10 days after filing a rate review and Iowa Gas implemented interim rates effective on June 11, 2021. The request seeks to finalize rates in the first quarter of 2022.

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. Additionally, Kansas Gas is seeking renewal of its SSIR. The rate review requests shifting $4.9 million of rider revenue to base rates and $5.3 million in new annual revenue with a capital structure of 50% equity and 50% debt and a return on equity of 10.15%. The request seeks to implement new rates in the first quarter of 2022.

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 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 an authorized return on equity of 9.5%. The approval also includes an extension of the SSIR for five years and an expansion of this mechanism across the consolidated jurisdictions.

(3) Commitments, Contingencies and Guarantees

There have been no significant changes to commitments, contingencies and guarantees from those previously disclosed in Note 3 of our Notes to the Consolidated Financial Statements in our 2020 Annual Report on Form 10-K except for those described below.

Power Purchase Agreement - Colorado Electric Renewable Advantage

On February 19, 2021, Colorado Electric entered into a PPA with TC Colorado Solar, LLC to purchase up to 200 MW of renewable energy upon construction of a new solar facility, to be owned by TC Colorado Solar, LLC, which is expected to be completed by the end of 2023. This agreement will expire 15 years after construction completion. The solar project represents Colorado Electric’s preferred bid in a competitive solicitation process completed in September 2020 through its Renewable Advantage plan.

(4) Revenue

Our revenue contracts generally provide for performance obligations that are: fulfilled and transfer control to customers over time; represent a series of distinct services that are substantially the same; involve the same pattern of transfer to the customer; and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice. 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 three and six months ended June 30, 2021 and 2020. Sales tax and other similar taxes are excluded from revenues.

Three Months Ended June 30, 2021	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:			(in thousands)			
Retail	$ 158,470	$ 143,845	$ —	$ 13,854	$ (7,140)	$ 309,029
Transportation	—	31,649	—	—	(109)	31,540
Wholesale	3,010	—	24,912	—	(23,480)	4,442
Market - off-system sales	8,941	87	—	—	(1,675)	7,353
Transmission/Other	12,233	9,125	—	—	(5,299)	16,059
Revenue from contracts with customers	$ 182,654	$ 184,706	$ 24,912	$ 13,854	$ (37,703)	$ 368,423
Other revenues	2,279	1,344	436	575	(485)	4,149
Total revenues	$ 184,933	$ 186,050	$ 25,348	$ 14,429	$ (38,188)	$ 372,572
Timing of revenue recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 13,854	$ (7,140)	$ 6,714
Services transferred over time	182,654	184,706	24,912	—	(30,563)	361,709
Revenue from contracts with customers	$ 182,654	$ 184,706	$ 24,912	$ 13,854	$ (37,703)	$ 368,423

Three Months Ended June 30, 2020	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer Types:			(in thousands)			
Retail	$ 141,804	$ 120,594	$ —	$ 14,846	$ (7,916)	$ 269,328
Transportation	—	30,792	—	—	(138)	30,654
Wholesale	3,470	—	25,718	—	(24,476)	4,712
Market - off-system sales	3,538	23	—	—	(1,580)	1,981
Transmission/Other	12,761	9,189	—	—	(4,432)	17,518
Revenue from contracts with customers	$ 161,573	$ 160,598	$ 25,718	$ 14,846	$ (38,542)	$ 324,193
Other revenues	1,627	512	404	570	(392)	2,721
Total Revenues	$ 163,200	$ 161,110	$ 26,122	$ 15,416	$ (38,934)	$ 326,914
Timing of Revenue Recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 14,846	$ (7,916)	$ 6,930
Services transferred over time	161,573	160,598	25,718	—	(30,626)	317,263
Revenue from contracts with customers	$ 161,573	$ 160,598	$ 25,718	$ 14,846	$ (38,542)	$ 324,193

Six Months Ended June 30, 2021	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:			(in thousands)			
Retail	$ 356,970	$ 485,450	$ —	$ 27,937	$ (14,247)	$ 856,110
Transportation	—	79,600	—	—	(219)	79,381
Wholesale	8,932	—	53,604	—	(47,931)	14,605
Market - off-system sales	16,597	160	—	—	(4,559)	12,198
Transmission/Other	27,426	19,515	—	—	(10,595)	36,346
Revenue from contracts with customers	$ 409,925	$ 584,725	$ 53,604	$ 27,937	$ (77,551)	$ 998,640
Other revenues	2,416	3,844	907	1,164	(967)	7,364
Total revenues	$ 412,341	$ 588,569	$ 54,511	$ 29,101	$ (78,518)	$ 1,006,004
Timing of revenue recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 27,937	$ (14,247)	$ 13,690
Services transferred over time	409,925	584,725	53,604	—	(63,304)	984,950
Revenue from contracts with customers	$ 409,925	$ 584,725	$ 53,604	$ 27,937	$ (77,551)	$ 998,640

Six Months Ended June 30, 2020	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer Types:			(in thousands)			
Retail	$ 290,444	$ 418,841	$ —	$ 29,249	$ (15,755)	$ 722,779
Transportation	—	74,900	—	—	(277)	74,623
Wholesale	9,022	—	51,185	—	(48,088)	12,119
Market - off-system sales	8,405	161	—	—	(4,219)	4,347
Transmission/Other	27,618	21,761	—	—	(8,845)	40,534
Revenue from contracts with customers	$ 335,489	$ 515,663	$ 51,185	$ 29,249	$ (77,184)	$ 854,402
Other revenues	1,850	6,220	903	1,372	(783)	9,562
Total Revenues	$ 337,339	$ 521,883	$ 52,088	$ 30,621	$ (77,967)	$ 863,964
Timing of Revenue Recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 29,249	$ (15,755)	$ 13,494
Services transferred over time	335,489	515,663	51,185	—	(61,429)	840,908
Revenue from contracts with customers	$ 335,489	$ 515,663	$ 51,185	$ 29,249	$ (77,184)	$ 854,402

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 further discussed in Note 13.

(5) Financing

Short-term debt

We had the following Notes payable outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	June 30, 2021		December 31, 2020	
	Balance Outstanding	Letters of Credit [(a)]	Balance Outstanding	Letters of Credit [(a)]
Term Loan	$ 600,000	$ —	$ —	$ —
Revolving Credit Facility	—	13,049	—	24,730
CP Program	229,850	—	234,040	—
Total Notes payable	$ 829,850	$ 13,049	$ 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.

Term Loan

On February 24, 2021, we entered into a nine-month, $800 million unsecured term loan to provide additional liquidity and meet our cash needs related to the incremental fuel, purchased power and natural gas costs from Winter Storm Uri. The term loan, which matures on November 24, 2021, has an interest rate based on LIBOR plus 75 basis points, carries no prepayment penalty and is 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. The interest rate on term loan borrowings on June 30, 2021 was 0.85%.

We expect to refinance a portion of the term loan with longer-term debt prior to maturity. In the event we are unable to refinance the remaining obligation, we believe it is probable that our current plans to manage liquidity would be sufficient to meet our obligations.

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 facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. Based on our current credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit will be 0.125%, 1.125% and 1.125%, respectively, and a 0.175% commitment fee will be charged on unused amounts.

Our net short-term borrowings related to our Revolving Credit Facility and CP Program during the six months ended June 30, 2021 decreased by $4.2 million. The weighted average interest rate on short-term borrowings related to our Revolving Credit Facility and CP Program at June 30, 2021 was 0.19%.

Debt Covenants

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

Our Revolving Credit Facility and term loans require compliance with the following financial covenant, which we were in compliance with at June 30, 2021:

	As of June 30, 2021	Covenant Requirement	
Consolidated Indebtedness to Capitalization Ratio	62.3%	Less than	65%

Equity

At-the-Market Equity Offering Program

During the three and six months ended June 30, 2021, we issued a total of 0.6 million shares of common stock under the ATM for proceeds of $40 million, net of $0.4 million in issuance costs.

(6) Earnings Per Share

A reconciliation of share amounts used to compute earnings per share in the accompanying Condensed Consolidated Statements of Income was as follows (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Net income available for common stock	$ 25,161	$ 20,966	$ 121,477	$ 114,140
Weighted average shares - basic	62,867	62,573	62,751	62,175
Dilutive effect of:				
Equity compensation	51	44	66	55
Weighted average shares - diluted	62,918	62,617	62,817	62,230
Earnings per share of common stock:				
Earnings per share, Basic	$ 0.40	$ 0.34	$ 1.94	$ 1.84
Earnings per share, Diluted	$ 0.40	$ 0.33	$ 1.93	$ 1.83

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Equity compensation	13	29	12	26
Restricted stock	—	76	1	36
Anti-dilutive shares	13	105	13	62

(7) Risk Management and Derivatives

Market and Credit Risk Disclosures

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

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

- Commodity price risk associated with our retail natural gas and wholesale electric power marketing activities, as well as our fuel procurement for several of our gas-fired generation assets, which include market fluctuations due to unpredictable factors such as weather (Winter Storm Uri), market speculation, 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

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.

Derivatives and Hedging Activity

Our derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Comprehensive Income are detailed below and in Note 8.

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities’ generating facilities or those facilities 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. 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 Condensed 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 Condensed Consolidated Balance Sheets in accordance with the state regulatory commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Condensed Consolidated Statements of Income.

We periodically use wholesale power purchase and sale contracts 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 purchases and normal sales exception to derivative accounting. Changes in the fair value of these commodity derivatives are recognized in the Condensed 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 risk using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and sales during time frames ranging from July 2021 through August 2023. 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 Condensed 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 electric and natural gas derivative commodity instruments held at our Utilities are composed of both long and short positions. We had the following net long positions as of:

		June 30, 2021		December 31, 2020	
	Units	Notional Amounts	Maximum Term (months) [a]	Notional Amounts	Maximum Term (months) [a]
Natural gas futures purchased	MMBtus	100,000	9	620,000	3
Natural gas options purchased, net	MMBtus	970,000	9	3,160,000	3
Natural gas basis swaps purchased	MMBtus	—	9	900,000	3
Natural gas over-the-counter swaps, net [b]	MMBtus	6,660,000	26	3,850,000	17
Natural gas physical contracts, net [c]	MMBtus	4,902,179	9	17,513,061	22
Electric wholesale contracts [c]	MWh	110,425	6	219,000	12

(a) Term reflects the maximum forward period hedged.
(b) As of June 30, 2021, 3,030,000 MMBtus of natural gas over-the-counter swaps purchases were designated as cash flow hedges.
(c) Volumes exclude derivative contracts that qualify for the normal purchases and 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 June 30, 2021, the Company posted $1.0 million related to such provisions, which is included in Other current assets on the Condensed 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 table presents the fair value and balance sheet classification of our derivative instruments (in thousands) as of:

	Balance Sheet Location	June 30, 2021	December 31, 2020
Derivatives designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets, current	$ 1,549	$ 181
Noncurrent commodity derivatives	Other assets, non-current	5	43
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities, current	—	(108)
Total derivatives designated as hedges		$ 1,554	$ 116
Derivatives not designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets, current	$ 2,376	$ 1,667
Noncurrent commodity derivatives	Other assets, non-current	375	151
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities, current	(5,178)	(1,936)
Total derivatives not designated as hedges		$ (2,427)	$ (118)

Derivatives Designated as Hedge Instruments

The impacts of cash flow hedges on our Condensed Consolidated Statements of Comprehensive Income and Condensed Consolidated Statements of Income are presented below for the three and six months ended June 30, 2021 and 2020. Note that this presentation does not reflect 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.

	Three Months Ended June 30,			Three Months Ended June 30,	
	2021	2020		2021	2020
Derivatives in Cash Flow Hedging Relationships	Amount of (Gain)/Loss Recognized in OCI		Income Statement Location	Amount of Gain/(Loss) Reclassified from AOCI into Income	
	(in thousands)			(in thousands)	
Interest rate swaps	$ 713	$ 713	Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	$ (713)	$ (713)
Commodity derivatives	1,187	11	Fuel, purchased power and cost of natural gas sold	56	(70)
Total	$ 1,900	$ 724		$ (657)	$ (783)

	Six Months Ended June 30,			Six Months Ended June 30,	
	2021	2020		2021	2020
Derivatives in Cash Flow Hedging Relationships	Amount of (Gain)/Loss Recognized in OCI		Income Statement Location	Amount of Gain/(Loss) Reclassified from AOCI into Income	
	(in thousands)			(in thousands)	
Interest rate swaps	$ 1,426	$ 1,426	Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	$ (1,426)	$ (1,426)
Commodity derivatives	1,360	268	Fuel, purchased power and cost of natural gas sold	25	(556)
Total	$ 2,786	$ 1,694		$ (1,401)	$ (1,982)

As of June 30, 2021, $2.8 million of net losses related to our interest rate swaps and commodity derivatives are expected to be reclassified from AOCI into earnings as losses 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 Condensed Consolidated Statements of Income for the three and six months ended June 30, 2021 and 2020. Note that this presentation does not reflect 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.

		Three Months Ended June 30,	
		2021	2020
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	
		(in thousands)	
Commodity derivatives - Electric	Fuel, purchased power and cost of natural gas sold	$ (3,598)	$ (204)
Commodity derivatives - Natural Gas	Fuel, purchased power and cost of natural gas sold	1,816	449
		$ (1,782)	$ 245

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
		Amount of Gain/(Loss) on Derivatives Recognized in Income (in thousands)	
Commodity derivatives - Electric	Fuel, purchased power and cost of natural gas sold	$ (5,122)	$ 1,158
Commodity derivatives - Natural Gas	Fuel, purchased power and cost of natural gas sold	2,182	1,215
		$ (2,940)	$ 2,373

As discussed above, financial instruments used in our regulated Gas Utilities are not designated as cash flow hedges. 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 asset or Regulatory liability related to the hedges in our Gas Utilities were $0.1 million and $2.2 million as of June 30, 2021 and December 31, 2020, respectively. For our Electric Utilities, the unrealized gains and losses arising from these derivatives are recognized in the Condensed Consolidated Statements of Income.

(8) Fair Value Measurements

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

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

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

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

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

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

Recurring Fair Value Measurements

Derivatives

The commodity contracts for our Utilities segments 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 wholesale electric energy and natural gas contracts. 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. For additional information, see Note 1 of our Notes to the Consolidated Financial Statements in our 2020 Annual Report on Form 10-K.

	As of June 30, 2021				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Gas Utilities	$ —	$ 4,895	$ —	$ (590)	$ 4,305
Commodity derivatives — Electric Utilities	$ —	$ —	$ —	$ —	$ —
Total	$ —	$ 4,895	$ —	$ (590)	$ 4,305
Liabilities:					
Commodity derivatives — Gas Utilities	$ —	$ 200	$ —	$ —	$ 200
Commodity derivatives — Electric Utilities	$ —	$ 4,978	$ —	$ —	$ 4,978
Total	$ —	$ 5,178	$ —	$ —	$ 5,178

	As of December 31, 2020				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
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

Pension and Postretirement Plan Assets

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about the fair value measurements of their assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 15 to the Consolidated Financial Statements included in our 2020 Annual Report on Form 10-K.

Other fair value measures

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 since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.

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

	June 30, 2021		December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current maturities [(a)]	$ 3,537,216	$ 4,035,612	$ 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 as Level 2 in the fair value hierarchy. Carrying amount of long-term debt is net of deferred financing costs.

(9) 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 Condensed Consolidated Statements of Income for the period (in thousands):

		Amount Reclassified from AOCI			
		Three Months Ended June 30,		Six Months Ended June 30,	
	Location on the Condensed Consolidated Statements of Income	2021	2020	2021	2020
Gains and (losses) on cash flow hedges:					
Interest rate swaps	Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	$ (713)	$ (713)	$ (1,426)	$ (1,426)
Commodity contracts	Fuel, purchased power and cost of natural gas sold	56	(70)	25	(556)
		(657)	(783)	(1,401)	(1,982)
Income tax	Income tax (expense)	136	186	334	471
Total reclassification adjustments related to cash flow hedges, net of tax		$ (521)	$ (597)	$ (1,067)	$ (1,511)
Amortization of components of defined benefit plans:					
Prior service cost	Operations and maintenance	$ 24	$ 25	$ 49	$ 55
Actuarial gain (loss)	Operations and maintenance	(597)	(597)	(1,195)	(1,194)
		(573)	(572)	(1,146)	(1,139)
Income tax	Income tax (expense)	151	176	359	264
Total reclassification adjustments related to defined benefit plans, net of tax		$ (422)	$ (396)	$ (787)	$ (875)
Total reclassifications		$ (943)	$ (993)	$ (1,854)	$ (2,386)

Balances by classification included within AOCI, net of tax on the accompanying Condensed 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	—	1,046	—	1,046
Amounts reclassified from AOCI	1,086	(19)	787	1,854
As of June 30, 2021	$ (11,472)	$ 1,029	$ (14,003)	$ (24,446)

	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	—	(220)	55	(165)
Amounts reclassified from AOCI	1,087	424	875	2,386
As of June 30, 2020	$ (14,035)	$ (252)	$ (14,147)	$ (28,434)

(10) Employee Benefit Plans

Defined Benefit Pension Plan

The components of net periodic benefit cost for the Defined Benefit Pension Plan were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Service cost	$ 1,260	$ 1,353	$ 2,519	$ 2,706
Interest cost	2,328	3,356	4,656	6,713
Expected return on plan assets	(5,219)	(5,648)	(10,438)	(11,296)
Net loss	1,829	2,093	3,658	4,186
Net periodic benefit cost	$ 198	$ 1,154	$ 395	$ 2,309

Defined Benefit Postretirement Healthcare Plan

The components of net periodic benefit cost for the Defined Benefit Postretirement Healthcare Plan were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Service cost	$ 559	$ 514	$ 1,118	$ 1,028
Interest cost	264	413	529	825
Expected return on plan assets	(34)	(46)	(68)	(91)
Prior service cost (benefit)	(109)	(137)	(218)	(274)
Net loss	117	5	234	10
Net periodic benefit cost	$ 797	$ 749	$ 1,595	$ 1,498

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

The components of net periodic benefit cost for the Supplemental Non-qualified Defined Benefit and Defined Contribution Plans were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Service cost	$ 1,020	$ 1,817	$ 1,713	$ 447
Interest cost	177	275	354	550
Net loss	438	426	877	852
Net periodic benefit cost	$ 1,635	$ 2,518	$ 2,944	$ 1,849

Contributions

Contributions to the Defined Benefit Pension Plan are cash contributions made directly to the Pension Plan Trust account. Contributions to the Postretirement Healthcare and Supplemental Plans are made in the form of benefit payments. Contributions made in the first six months of 2021 and anticipated contributions for 2021 and 2022 are as follows (in thousands):

	Contributions Made Six Months Ended June 30, 2021	Additional Contributions Anticipated for 2021	Contributions Anticipated for 2022
Defined Benefit Pension Plan	$ —	$ —	$ 3,788
Non-pension Defined Benefit Postretirement Healthcare Plan	$ 2,763	$ 2,763	$ 5,241
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 964	$ 964	$ 1,967

(11) 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 of approximately $132 million. 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 NOL in our 2021 federal and state income tax returns. Our federal NOL carryforwards no longer expire due to the TCJA; however, our state NOL carryforwards expire at various dates from 2021 to 2040. 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 June 30, 2021.

Income Tax (Expense) and Effective Tax Rates

Three Months Ended June 30, 2021 Compared to the Three Months Ended June 30, 2020

Income tax (expense) for the three months ended June 30, 2021 was $(0.6) million compared to $(4.8) million reported for the same period in 2020. For the three months ended June 30, 2021 the effective tax rate was 2.0% compared to 16.4% for the same period in 2020. The lower effective tax rate is primarily due to $2.2 million of increased tax benefits from Nebraska Gas TCJA-related bill credits to customers (which is offset by reduced revenue) and $1.9 million of increased flow-through tax benefits related to repairs and certain indirect costs.

Six Months Ended June 30, 2021 Compared to the Six Months Ended June 30, 2020

Income tax (expense) for the six months ended June 30, 2021 was $(1.1) million compared to $(21) million reported for the same period in 2020. For the six months ended June 30, 2021, the effective tax rate was 0.8% compared to 14.6% for the same period 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), $3.0 million of increased flow-through tax benefits related to repairs and certain indirect costs, $1.6 million of increased tax benefits from federal production tax credits associated with new wind assets and $1.4 million of increased tax benefits from amortization of excess deferred income taxes.

(12) Business Segment Information

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

Accounting standards for presentation of segments require an approach based on the way we organize the segments for making operating decisions and how the Chief Operating Decision Maker (CODM) assesses performance. The CODM assesses the performance of our segments using adjusted operating income, which recognizes intersegment revenues, costs, and assets for Colorado Electric's PPA with Black Hills Colorado IPP on an accrual basis rather than as a finance lease. This presentation of segment information does not impact consolidated financial results.

Segment information was as follows (in thousands):

Total assets (net of intercompany eliminations) as of:	June 30, 2021	December 31, 2020
Electric Utilities	$ 3,239,628	$ 3,120,928
Gas Utilities	4,935,784	4,376,204
Power Generation	394,213	404,220
Mining	75,109	77,085
Corporate and Other	93,318	110,349
Total assets	$ 8,738,052	$ 8,088,786

	External Operating Revenue		Inter-company Operating Revenue		
ree Months Ended June 30, 2021	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
gment:					
Electric Utilities	$ 177,092	$ 2,279	$ 5,562	$ —	$ 184,933
Gas Utilities	183,187	1,250	1,519	94	186,050
Power Generation	1,432	386	23,480	50	25,348
Mining	6,712	234	7,142	341	14,429
er-company eliminations	—	—	(37,703)	(485)	(38,188)
tal	$ 368,423	$ 4,149	$ —	$ —	$ 372,572

	External Operating Revenue		Inter-company Operating Revenue		
ree Months Ended June 30, 2020	Contract Customers	Other Revenues	Contract Customers	Other Revenues	Total Revenues
gment:					
Electric Utilities	$ 156,197	$ 1,627	$ 5,376	$ —	$ 163,200
Gas Utilities	159,824	512	774	—	161,110
Power Generation	1,242	349	24,476	55	26,122
Mining	6,930	233	7,916	337	15,416
er-company eliminations	—	—	(38,542)	(392)	(38,934)
tal	$ 324,193	$ 2,721	$ —	$ —	$ 326,914

Months Ended June 30, 2021	External Operating Revenue Contract Customers	External Operating Revenue Other Revenues	Inter-company Operating Revenue Contract Customers	Inter-company Operating Revenue Other Revenues	Total Revenues
gment:					
lectric Utilities	$ 397,592	$ 2,416	$ 12,333	$ —	$ 412,341
as Utilities	581,686	3,658	3,039	186	588,569
ower Generation	5,673	807	47,931	100	54,511
ining	13,689	483	14,248	681	29,101
er-company eliminations	—	—	(77,551)	(967)	(78,518)
tal	$ 998,640	$ 7,364	$ —	$ —	$ 1,006,004

Six Months Ended June 30, 2020	External Operating Revenue Contract Customers	External Operating Revenue Other Revenues	Inter-company Operating Revenue Contract Customers	Inter-company Operating Revenue Other Revenues	Total Revenues
Segment:					
Electric Utilities	$ 323,700	$ 1,850	$ 11,789	$ —	$ 337,339
Gas Utilities	514,111	6,220	1,552	—	521,883
Power Generation	3,097	792	48,088	111	52,088
Mining	13,494	700	15,755	672	30,621
Inter-company eliminations	—	—	(77,184)	(783)	(77,967)
Total	$ 854,402	$ 9,562	$ —	$ —	$ 863,964

	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
justed operating income:				
lectric Utilities	$ 35,568	$ 33,993	$ 57,381	$ 69,643
as Utilities	19,985	18,209	122,079	121,106
ower Generation	8,250	11,402	22,519	22,751
ining	3,644	3,358	6,905	6,487
orporate and Other	(181)	(29)	(3,303)	131
erating income	67,266	66,933	205,581	220,118
erest expense, net	(38,202)	(35,545)	(75,802)	(70,998)
pairment of investment	—	—	—	(6,859)
er income (expense), net	(191)	(1,863)	75	490
come tax (expense)	(586)	(4,831)	(1,080)	(20,833)
t income	28,287	24,694	128,774	121,918
t income attributable to noncontrolling interest	(3,126)	(3,728)	(7,297)	(7,778)
t income available for common stock	$ 25,161	$ 20,966	$ 121,477	$ 114,140

(13) Selected Balance Sheet Information

Accounts Receivable and Allowance for Credit Losses

Following is a summary of Accounts receivable, net included in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	June 30, 2021	December 31, 2020
Accounts receivable, trade	$ 132,400	$ 146,899
Unbilled revenue	63,066	126,065
Less: Allowance for credit losses	(6,029)	(7,003)
Accounts receivable, net	$ 189,437	$ 265,961

Changes to allowance for credit losses for the six months ended June 30, 2021 and 2020, respectively, 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 June 30,
2021	$ 7,003	$ 1,510	$ 1,786	$ (4,270)	$ 6,029
2020	$ 2,444	$ 6,715	$ 2,203	$ (3,777)	$ 7,585

Materials, Supplies and Fuel

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

	June 30, 2021	December 31, 2020
Materials and supplies	$ 85,277	$ 85,250
Fuel - Electric Utilities	2,310	1,531
Natural gas in storage	26,502	30,619
Total materials, supplies and fuel	$ 114,089	$ 117,400

Accrued Liabilities

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

	June 30, 2021	December 31, 2020
Accrued employee compensation, benefits and withholdings	$ 69,067	$ 77,806
Accrued property taxes	39,416	47,105
Customer deposits and prepayments	47,583	52,185
Accrued interest	31,762	31,520
Other (none of which is individually significant)	31,194	34,996
Total accrued liabilities	$ 219,022	$ 243,612

(14) Subsequent Events

We evaluated all subsequent event activity and concluded that no subsequent events have occurred that would require recognition in the condensed consolidated financial statements or disclosures, with the exception of Colorado Gas regulatory activity disclosed in Note 2 and our amended and restated corporate Revolving Credit Facility disclosed in Note 5.

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussions should be read in conjunction with the Notes contained herein and Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in the 2020 Form 10-K.

Executive Summary

We are a customer-focused, growth-oriented electric and natural gas utility company with a mission of Improving Life with Energy and a vision to be the Energy Partner of Choice. The Company provides electric and natural gas utility service to 1.3 million customers over 800 communities in eight states, including Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming.

Recent Developments

Winter Storm Uri

In February 2021, a prolonged period of historic cold temperatures across the central United States, which 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 meet our cash needs related to the incremental fuel, purchased power and natural gas costs from Winter Storm Uri. See Note 5 of the Notes to Condensed Consolidated Financial Statements for further term loan 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. See Note 2 of the Notes to Condensed Consolidated Financial Statements for further information on our regulatory activity.

COVID-19 Update

For the six months ended June 30, 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 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.

We continue to provide periodic status updates and maintain ongoing dialogue with the regulatory commissions in our jurisdictions regarding our right to preserve deferred regulatory treatment for certain COVID-19 related costs and to seek recovery of these costs at a later date.

As we look forward, our operating results from COVID-19 could be affected as discussed in the “Risk Factors” section in Part I, Item 1A of our 2020 Annual Report on Form 10-K.

Business Segment Highlights and Corporate Activity

Electric Utilities

- 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. The IRP outlines a range of options for the two electric utilities to meet long-term forecasted energy needs over a 20-year planning horizon 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.

- On February 19, 2021, Colorado Electric entered into a PPA with TC Colorado Solar, LLC to purchase up to 200 MW of renewable energy upon construction of a new solar facility, to be owned by TC Colorado Solar, LLC, which is expected to be completed by the end of 2023. This agreement will expire 15 years after construction completion. The utility-scale solar project represents Colorado Electric's preferred bid in a competitive solicitation process completed in September 2020 through its Renewable Advantage plan. With the addition of 200 MW of solar energy on its system, more than half of Colorado Electric's generation is forecasted to be sourced from renewable energy resources by 2023, leading to a 70% reduction in carbon emissions by 2024 compared to the 2005 base year.

- On February 11, 2021, South Dakota Electric set a new winter peak load of 326 MW, surpassing the previous winter peak of 320 MW set in February 2019.

Gas Utilities

- See Note 2 for recent regulatory activity for our Gas Utilities in Colorado, Iowa, Kansas and Nebraska.

Corporate and Other

- On July 19, 2021, we amended and restated our corporate Revolving Credit Facility. See Note 5 for further information.

Results of Operations

The segment information does not include inter-company eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated.

Certain lines of business in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements. In particular, the normal peak usage season for our Electric Utilities is June through August while the normal peak usage season for our Gas Utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2021 and 2020, and our financial condition as of June 30, 2021 and December 31, 2020, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period or for the entire year.

Consolidated Summary and Overview

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(in thousands, except per share amounts)			
Adjusted operating income [(a)]:				
Electric Utilities	$ 35,568	$ 33,993	$ 57,381	$ 69,643
Gas Utilities	19,985	18,209	122,079	121,106
Power Generation	8,250	11,402	22,519	22,751
Mining	3,644	3,358	6,905	6,487
Corporate and Other	(181)	(29)	(3,303)	131
Operating income	67,266	66,933	205,581	220,118
Interest expense, net	(38,202)	(35,545)	(75,802)	(70,998)
Impairment of investment	—	—	—	(6,859)
Other income (expense), net	(191)	(1,863)	75	490
Income tax (expense)	(586)	(4,831)	(1,080)	(20,833)
Net income	28,287	24,694	128,774	121,918
Net income attributable to noncontrolling interest	(3,126)	(3,728)	(7,297)	(7,778)
Net income available for common stock	$ 25,161	$ 20,966	121,477	114,140
Total earnings per share of common stock, Diluted	$ 0.40	$ 0.33	$ 1.93	$ 1.83

(a) Adjusted operating income recognizes intersegment revenues and costs for Colorado Electric's PPA with Black Hills Colorado IPP on an accrual basis rather than as a finance lease. This presentation of segment information does not impact consolidated financial results.

Three Months Ended June 30, 2021 Compared to Three Months Ended June 30, 2020

The variance to the prior year included the following:

- Electric Utilities' adjusted operating income increased $1.6 million primarily due to increased wholesale, power marketing and Tech Services revenues, increased rider revenues, regulatory actions reducing certain Winter Storm Uri impacts, and prior year COVID-19 impacts which were partially offset by unfavorable mark-to-market adjustments on wholesale energy contacts and higher operating expenses;
- Gas Utilities' adjusted operating income increased $1.8 million primarily due to new rates, favorable market-to-market adjustments on wholesale commodity contracts and prior year COVID-19 impacts partially offset by Nebraska Gas's TCJA-related bill credits to customers and higher operating expenses;
- Power Generation's adjusted operating income decreased $3.2 million primarily driven by current year planned outages;
- A $2.7 million increase in interest expense due to higher debt balances partially offset by lower rates;
- A $1.7 million increase in other income primarily due to lower non-service pension costs driven by a lower discount rate and lower costs for our non-qualified benefit plans which were driven by market performance; and
- A $4.2 million decrease in income tax expense due to a lower effective tax rate driven primarily by tax benefits from Nebraska Gas's TCJA-related bill credits and flow-through tax benefits related to repairs and certain indirect costs.

Six Months Ended June 30, 2021 Compared to Six Months Ended June 30, 2020

The variance to the prior year included the following:

- Electric Utilities' adjusted operating income decreased $12 million primarily due to Colorado Electric's TCJA-related bill credits to customers, impacts from Winter Storm Uri and unfavorable mark-to-market adjustments on wholesale energy contracts partially offset by increased rider revenues, increased wholesale, power marketing and Tech Services revenues and prior year COVID-19 impacts;
- Gas Utilities' adjusted operating income increased $1.0 million primarily due to new rates and higher heating demand from colder weather mostly offset by Winter Storm Uri costs incurred by Black Hills Energy Services, Nebraska Gas TCJA-related bill credits to customers, and higher operating expenses;
- Corporate and Other expenses increased $3.4 million primarily due to a prior year favorable true-up of employee costs allocated to our subsidiaries in the current year, which is offset in our business segments;
- A $4.8 million increase in interest expense due to higher debt balances partially offset by lower rates;
- A prior year $6.9 million pre-tax non-cash impairment of our investment in equity securities of a privately held oil and gas company;
- A $19.8 million decrease in income tax expense 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, flow-through tax benefits related to repairs and certain indirect costs, amortization of excess deferred income taxes and federal production tax credits associated with new wind assets.

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, gross 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. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation and amortization from the measure. The presentation of gross margin is intended to supplement investors' understanding of our operating performance.

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

Our gross margin measure may not be comparable to other companies' gross margin measure. 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 Electric Utilities were as follows (in thousands):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2021	2020	Variance	2021	2020	Variance
Revenue	$ 184,933	$ 163,200	$ 21,733	$ 412,341	$ 337,339	$ 75,002
Total fuel and purchased power	75,238	59,053	16,185	207,307	123,513	83,794
Gross margin (non-GAAP)	109,695	104,147	5,548	205,034	213,826	(8,792)
Operations and maintenance	48,962	47,031	1,931	97,539	97,530	9
Depreciation and amortization	25,165	23,123	2,042	50,114	46,653	3,461
Total operating expenses	74,127	70,154	3,973	147,653	144,183	3,470
Adjusted operating income	$ 35,568	$ 33,993	$ 1,575	$ 57,381	$ 69,643	$ (12,262)

Three Months Ended June 30, 2021 Compared to the Three Months Ended June 30, 2020:

Gross margin for the three months ended June 30, 2021 increased as a result of the following:

	(in millions)
Rider recovery	2.7
Winter Storm Uri impacts [a]	2.4
Wholesale, Power Marketing and Tech Services	2.2
Prior year COVID-19 impacts	1.5
Residential customer growth	0.4
Mark-to-market on wholesale energy contracts [b]	(3.4)
TCJA-related bill credits [c]	(0.9)
Weather	(0.7)
Other	1.3
Total change in Gross margin (non-GAAP)	$ 5.5

(a) In the first quarter 2021,our Electric Utilities accrued $3.2 million of negative impacts to our regulated wholesale power margins due to the higher fuel costs associated with Winter Storm Uri. Through regulatory actions in the second quarter of 2021, our Electric Utilities were able to reduce $2.4 million of that negative impact.

(b) Mark-to-market losses of $3.6 million for the three months ended June 30, 2021 will reverse in the second half of 2021 as these fixed price wholesale energy contracts are settled.

(c) In 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.

Operations and maintenance expense increased primarily due to higher maintenance costs related to planned and unplanned outages at the Gillette, Wyoming energy complex and higher operating expenses associated with Corriedale which was placed in service November 30, 2020.

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

Six Months Ended June 30, 2021 Compared to the Six Months Ended June 30, 2020:

Gross margin for the six months ended June 30, 2021 decreased as a result of the following:

	(in millions)
TCJA-related bill credits [(a)]	$ (10.2)
Mark-to-market on wholesale energy contracts [(b)]	(6.3)
Winter Storm Uri impacts [(c)]	(2.9)
Rider recovery	4.0
Wholesale, Power Marketing and Tech Services	2.7
Prior year COVID-19 impacts	1.5
Residential customer growth	0.7
Weather	0.4
Other	1.3
Total change in Gross margin (non-GAAP)	$ (8.8)

(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) Mark-to-market losses of $5.1 million for the six months ended June 30, 2021 will reverse in the second half of 2021 as these fixed price wholesale energy contracts are settled.

(c) As a result of Winter Storm Uri, our Electric Utilities incurred a $0.8 million negative impact to our regulated wholesale power margins due to higher fuel costs and $2.1 million of incremental fuel costs that are not recoverable through our fuel cost recovery mechanisms.

Operations and maintenance expense remained constant primarily due to higher maintenance costs related to planned and unplanned outages at the Gillette, Wyoming energy complex and higher operating expenses associated with Corriedale which was placed in service November 30, 2020, offset by prior year expenses related to the municipalization efforts in Pueblo, Colorado.

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

Operating Statistics

	Revenue (in thousands)				Quantities Sold (MWh)			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020	2021	2020	2021	2020
sidential	$ 53,451	$ 50,148	$ 126,211	$ 104,653	335,063	334,682	731,149	707,832
mmercial	66,809	56,400	143,816	114,223	501,463	459,632	994,418	953,940
lustrial	35,186	31,896	78,195	64,065	441,793	459,533	856,984	920,165
nicipal	4,382	4,020	9,402	7,898	39,863	38,372	76,105	74,771
Subtotal Retail Revenue - Electric	159,828	142,464	357,624	290,839	1,318,182	1,292,219	2,658,656	2,656,708
ntract Wholesale	5,751	3,470	14,216	9,023	129,763	87,253	286,758	219,031
-system/Power Marketing Wholesale	6,200	3,537	11,313	8,404	188,607	136,311	316,190	302,096
her	13,154	13,729	29,188	29,073	—	—	—	—
Total Revenue and Energy Sold	184,933	163,200	412,341	337,339	1,636,552	1,515,783	3,261,604	3,177,835
her Uses, Losses or Generation, net	—	—	—	—	93,747	85,185	224,722	176,056
Total Revenue and Energy	184,933	163,200	412,341	337,339	1,730,299	1,600,968	3,486,326	3,353,891
ss cost of fuel and purchased power	75,238	59,053	207,307	123,513				
Gross Margin (non-GAAP)	$ 109,695	$ 104,147	$ 205,034	213,826				

ree Months Ended June 30,	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Quantities Sold (MWh)[(a)]	
	2021	2020	2021	2020	2021	2020
lorado Electric	$ 64,313	$ 57,897	$ 34,409	32,455	618,806	547,814
uth Dakota Electric	73,494	62,587	51,892	49,973	630,055	570,528
yoming Electric	47,126	42,716	23,394	21,719	481,438	482,626
Total Electric Revenue, Gross Margin (non-GAAP), and Quantities Sold	$ 184,933	$ 163,200	$ 109,695	104,147	1,730,299	1,600,968

Six Months Ended June 30,	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Quantities Sold (MWh)[(a)]	
	2021	2020	2021	2020	2021	2020
Colorado Electric	$ 144,054	$ 116,455	$ 58,500	$ 64,725	1,225,149	1,098,585
South Dakota Electric	168,830	134,198	101,442	105,597	1,287,834	1,255,752
Wyoming Electric	99,457	86,686	45,092	43,504	973,343	999,554
Total Electric Revenue, Gross Margin (non-GAAP), and Quantities Sold	$ 412,341	$ 337,339	$ 205,034	$ 213,826	3,486,326	3,353,891

(a) Includes company uses, line losses, and excess exchange production.

antities Generated and Purchased (MWh)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
nerated:				
Coal	497,238	572,030	980,216	1,119,859
Natural Gas and Oil	171,610	86,798	303,715	254,542
Wind	107,178	63,628	225,157	137,178
Total Generated	776,026	722,456	1,509,088	1,511,579
rchased	954,273	878,512	1,977,238	1,842,312
al Generated and Purchased	1,730,299	1,600,968	3,486,326	3,353,891

antities Generated and Purchased (MWh)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
nerated:				
Colorado Electric	110,821	80,456	201,077	174,507
South Dakota Electric	442,665	442,566	911,481	915,532
Wyoming Electric	222,540	199,434	396,530	421,540
Total Generated	776,026	722,456	1,509,088	1,511,579
rchased:				
Colorado Electric	507,985	467,358	1,024,072	924,078
South Dakota Electric	187,389	127,962	376,353	340,220
Wyoming Electric	258,899	283,192	576,813	578,014
Total Purchased	954,273	878,512	1,977,238	1,842,312
al Generated and Purchased	1,730,299	1,600,968	3,486,326	3,353,891

	Three Months Ended June 30,			
	2021		2020	
Degree Days	Actual	Variance from Normal	Actual	Variance from Normal
Heating Degree Days:				
Colorado Electric	595	(6)%	518	(18)%
South Dakota Electric	1,048	2 %	1,127	10 %
Wyoming Electric	1,221	2 %	1,149	(4)%
Combined [(a)]	875	— %	853	(3)%
Cooling Degree Days:				
Colorado Electric	300	44 %	382	83 %
South Dakota Electric	167	69 %	120	21 %
Wyoming Electric	117	134 %	101	102 %
Combined [(a)]	218	56 %	236	69 %

	Six Months Ended June 30,			
	2021		2020	
Degree Days	Actual	Variance from Normal	Actual	Variance from Normal
Heating Degree Days				
Colorado Electric	3,326	2 %	2,974	(9)%
South Dakota Electric	4,372	3 %	4,238	— %
Wyoming Electric	4,482	6 %	4,148	(1)%
Combined [(a)]	3,915	3 %	3,642	(4)%
Cooling Degree Days:				
Colorado Electric	300	44 %	382	83 %
South Dakota Electric	167	69 %	120	21 %
Wyoming Electric	117	134 %	101	102 %
Combined [(a)]	218	56 %	236	69 %

(a) Combined actuals are calculated based on the weighted average number of total customers by state.

	Three Months Ended June 30,		Six Months Ended June 30,	
Contracted generating facilities availability by fuel type [(a)]	2021	2020	2021	2020
Coal [(b)]	85.4 %	94.1 %	84.6 %	92.5 %
Natural Gas and diesel oil [(b)] [(c)]	97.2 %	78.3 %	92.4 %	80.9 %
Wind	96.4 %	98.1 %	94.9 %	98.6 %
Total availability	93.4 %	85.0 %	90.3 %	86.0 %
Wind capacity factor	36.9 %	39.0 %	40.0 %	42.3 %

(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, Wygen III and Pueblo Airport Generation and unplanned outages at Neil Simpson II and Wyodak Plant.
(c) 2020 included an unplanned outage at Pueblo Airport Generation.

Gas Utilities

Operating results for the Gas Utilities were as follows (in thousands):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2021	2020	Variance	2021	2020	Variance
Revenue:						
Natural gas - regulated	$ 172,465	$ 148,432	$ 24,033	$ 550,542	$ 484,329	$ 66,213
Other - non-regulated services	13,585	12,678	907	38,027	37,554	473
Total revenue	186,050	161,110	24,940	588,569	521,883	66,686
Cost of sales:						
Natural gas - regulated	62,317	42,910	19,407	245,284	196,909	48,375
Other - non-regulated services	798	1,712	(914)	10,881	3,074	7,807
Total cost of sales	63,115	44,622	18,493	256,165	199,983	56,182
Gross margin (non-GAAP)	122,935	116,488	6,447	332,404	321,900	10,504
Operations and maintenance	77,263	72,415	4,848	159,463	149,709	9,754
Depreciation and amortization	25,687	25,864	(177)	50,862	51,085	(223)
Total operating expenses	102,950	98,279	4,671	210,325	200,794	9,531
Adjusted operating income	$ 19,985	$ 18,209	$ 1,776	$ 122,079	$ 121,106	$ 973

Three Months Ended June 30, 2021 Compared to the Three Months Ended June 30, 2020:

Gross margin for the three months ended June 30, 2021 increased as a result of:

	(in millions)
New rates	$ 5.5
Mark-to-market on non-utility natural gas commodity contracts	1.6
Prior year COVID-19 impacts	0.9
Weather	0.1
TCJA-related bill credits (a)	(2.9)
Other	1.2
Total increase in Gross margin (non-GAAP)	$ 6.4

(a) In June 2021, Nebraska Gas provided 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 due to $4.4 million of higher employee costs and outside services driven by higher headcount and higher stock compensation expense related to market performance, $1.6 million of increased facilities and office expenses, and $1.0 million of increased property taxes due to a higher asset base partially offset by $3.2 million of decreased bad debt expense associated with lower expected credit losses. Other expenses, none of which were individually significant, comprised the remainder of the difference when compared to the same period in the prior year.

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

Six Months Ended June 30, 2021 Compared to the Six Months Ended June 30, 2020:

Gross margin for the six months ended June 30, 2021 increased as a result of the following:

	(in millions)
New rates	$ 14.7
Weather	7.6
Mark-to-market on non-utility natural gas commodity contracts	1.2
Prior year COVID-19 impacts	0.9
Black Hills Energy Services Winter Storm Uri costs [(a)]	(8.2)
TCJA-related bill credits [(b)]	(2.9)
Non-utility - Service Guard Comfort Plan and Gas Supply Services	(2.3)
Other	(0.5)
Total increase in Gross margin (non-GAAP)	$ 10.5

(a) 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.

(b) 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 and outside services driven by higher headcount and higher stock compensation expense related to market performance, $2.2 million of higher facilities and office related expenses, and $1.6 million of increased property taxes due to a higher asset base partially offset by $3.4 million of decreased bad debt expense associated with lower expected credit losses.

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

Operating Statistics

	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Three Months Ended June 30,		Three Months Ended June 30,		Three Months Ended June 30,	
	2021	2020	2021	2020	2021	2020
Residential	$ 98,370	$ 83,240	$ 60,388	$ 56,368	8,575,051	8,501,835
Commercial	36,888	27,441	16,964	15,336	4,493,931	3,965,529
Industrial	5,811	6,059	1,400	2,140	1,337,672	2,036,553
Other	(418)	828	(418)	827	—	—
Total Distribution	140,651	117,568	78,334	74,671	14,406,654	14,503,917
Transportation and Transmission	31,814	30,864	31,814	30,851	34,074,214	30,243,501
Total Regulated	172,465	148,432	110,148	105,522	48,480,868	44,747,418
Non-regulated Services	13,585	12,678	12,787	10,966		
Total Gas Revenue & Gross Margin (non-GAAP)	$ 186,050	$ 161,110	$ 122,935	$ 116,488		

	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Six Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020	2021	2020
Residential	$ 332,767	$ 290,471	$ 170,536	$ 159,489	39,143,789	36,732,630
Commercial	127,977	107,677	52,448	48,855	18,306,252	16,800,332
Industrial	10,713	11,259	3,189	4,183	2,235,961	3,097,605
Other	(890)	(415)	(890)	(415)	—	—
Total Distribution	470,567	408,992	225,283	212,112	59,686,002	56,630,567
Transportation and Transmission	79,975	75,337	79,975	75,308	79,388,652	75,299,008
Total Regulated	550,542	484,329	305,258	287,420	139,074,654	131,929,575
Non-regulated Services	38,027	37,554	27,146	34,480		
Total Gas Revenue & Gross Margin (non-GAAP)	$ 588,569	$ 521,883	$ 332,404	$ 321,900		

	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Three Months Ended June 30,		Three Months Ended June 30,		Three Months Ended June 30,	
	2021	2020	2021	2020	2021	2020
Arkansas Gas	$ 32,994	$ 28,733	$ 22,902	$ 21,906	5,718,417	4,906,236
Colorado Gas	34,190	28,613	20,610	18,807	5,957,285	5,046,844
Iowa Gas	29,831	21,407	16,009	14,355	7,016,613	5,521,119
Kansas Gas	21,163	18,486	12,744	12,460	7,155,427	6,722,914
Nebraska Gas	43,037	40,466	32,095	30,719	15,822,880	13,822,478
Wyoming Gas	24,835	23,405	18,575	18,241	6,810,246	8,727,827
Total Gas Revenue & Gross Margin (non-GAAP)	$ 186,050	$ 161,110	$ 122,935	$ 116,488	48,480,868	44,747,418

	Revenue (in thousands)		Gross Margin (non-GAAP) (in thousands)		Gas Utilities Quantities Sold & Transported (Dth)	
	Six Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020	2021	2020
Arkansas Gas	$ 119,988	$ 103,578	$ 74,851	$ 70,761	19,025,151	15,869,184
Colorado Gas	113,312	101,219	58,822	56,813	19,323,300	18,143,249
Iowa Gas	86,585	76,231	38,640	35,683	21,330,586	19,801,392
Kansas Gas	61,226	51,980	31,510	31,063	17,618,224	16,637,772
Nebraska Gas	136,135	124,132	82,027	82,385	43,106,981	40,331,514
Wyoming Gas	71,323	64,743	46,554	45,195	18,670,412	21,146,464
Total Gas Revenue & Gross Margin (non-GAAP)	$ 588,569	$ 521,883	$ 332,404	$ 321,900	139,074,654	131,929,575

	Three Months Ended June 30,			
	2021		2020	
Heating Degree Days	Actual	Variance from Normal	Actual	Variance from Normal
Arkansas Gas [(a)]	383	16%	353	7%
Colorado Gas	865	(9)%	809	(15)%
Iowa Gas	691	1%	783	14%
Kansas Gas [(a)]	493	10%	477	7%
Nebraska Gas	624	(1)%	692	9%
Wyoming Gas	1,200	(1)%	1,216	—%
Combined Gas [(b)]	739	1%	688	2%

	Six Months Ended June 30,			
	2021		2020	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal
Arkansas Gas [(a)]	2,504	3%	2,012	(17)%
Colorado Gas	3,830	(1)%	3,638	(6)%
Iowa Gas	4,113	1%	3,964	(2)%
Kansas Gas [(a)]	3,069	5%	2,781	(4)%
Nebraska Gas	3,721	1%	3,527	(4)%
Wyoming Gas	4,625	5%	4,433	1%
Combined Gas [(b)]	3,925	2%	3,606	(4)%

(a) Arkansas Gas and Kansas Gas have weather normalization mechanisms that mitigate the weather impact on gross margins.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism. Arkansas Gas is partially excluded based on the weather normalization mechanism in effect from November through April.

Regulatory Matters

For more information on recent regulatory activity and enacted regulatory provisions with respect to the states in which our Utilities operate, see Note 2 of the Notes to Condensed Consolidated Financial Statements and Part I, Items 1 and 2 and Part II, Item 8 of our 2020 Annual Report on Form 10-K.

Power Generation

Our Power Generation segment operating results were as follows (in thousands):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2021	2020	Variance	2021	2020	Variance
Revenue	$ 25,348	$ 26,122	$ (774)	$ 54,511	$ 52,088	$ 2,423
Fuel expense	2,621	2,087	534	5,292	4,372	920
Operations and maintenance	9,322	7,350	1,972	16,680	14,347	2,333
Depreciation and amortization	5,155	5,283	(128)	10,020	10,618	(598)
Total operating expense	17,098	14,720	2,378	31,992	29,337	2,655
Adjusted operating income	$ 8,250	$ 11,402	$ (3,152)	$ 22,519	$ 22,751	$ (232)

Three Months Ended June 30, 2021 Compared to the Three Months Ended June 30, 2020:

The decrease in current year operating income was primarily driven by a current year planned outage at Pueblo Airport Generation and the timing of current year and prior year planned outages at the Gillette, Wyoming energy complex.

Six Months Ended June 30, 2021 Compared to the Six Months Ended June 30, 2020:

Operating income was comparable to the same period in the prior year due to negative impacts of a current year planned outage at Pueblo Airport Generation mostly offset by $1.7 million of favorable Winter Storm Uri impacts realized under Black Hills Wyoming's Economy Energy PSA.

Operating Statistics

	Revenue (in thousands)		Quantities Sold (MWh) [(a)]		Revenue (in thousands)		Quantities Sold (MWh) [(a)]	
	Three Months Ended June 30,				Six Months Ended June 30,			
	2021	2020	2021	2020	2021	2020	2021	2020
Black Hills Colorado IPP	$ 13,981	$ 14,211	204,065	263,701	$ 28,235	$ 28,390	443,259	528,926
Black Hills Wyoming [(b)]	10,141	10,488	141,809	156,866	23,574	20,646	306,766	313,218
Black Hills Electric Generation	1,226	1,423	88,724	92,629	2,702	3,052	185,018	189,908
Total Power Generation Revenue and Quantities Sold	$ 25,348	$ 26,122	434,598	513,196	$ 54,511	$ 52,088	935,043	1,032,052

Quantities Generated and Purchased (MWh) [(a)]	Fuel Type	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Generated					
Black Hills Colorado IPP	Natural Gas	204,065	263,701	443,259	528,926
Black Hills Wyoming [(b)]	Coal	128,270	142,747	264,374	269,232
Black Hills Electric Generation	Wind	88,724	92,629	185,018	189,908
Total Generated		421,059	499,077	892,651	988,066
Purchased					
Black Hills Wyoming [(b)]	Various	15,102	14,160	44,616	44,093
Total Purchased		15,102	14,160	44,616	44,093

(a) Company uses and losses are not included in the quantities sold, generated, and purchased.

(b) Under the 20-year Economy Energy PSA with the City of Gillette effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette. MWh sold may not equal MWh generated and purchased due to a dispatch agreement that Black Hills Wyoming has with South Dakota Electric to cover energy imbalances.

Contracted generating facilities availability by fuel type [(a)]	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Coal [(b)]	89.3 %	98.2 %	93.1 %	93.7 %
Natural gas [(b)]	87.6 %	99.7 %	93.1 %	99.6 %
Wind	97.2 %	93.1 %	95.7 %	94.0 %
Total availability	91.4 %	97.0 %	94.1 %	96.6 %
Wind capacity factor	26.5 %	27.5 %	27.7 %	28.9 %

(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 Wygen I and Pueblo Airport Generation.

Mining

Our Mining segment operating results were as follows (in thousands):

	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Three Months Ended June 30, Variance	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020	Six Months Ended June 30, Variance
Revenue	$ 14,429	$ 15,416	$ (987)	$ 29,101	$ 30,621	$ (1,520)
Operations and maintenance	8,415	9,732	(1,317)	17,612	19,558	(1,946)
Depreciation, depletion and amortization	2,370	2,326	44	4,584	4,576	8
Total operating expenses	10,785	12,058	(1,273)	22,196	24,134	(1,938)
Adjusted operating income	$ 3,644	$ 3,358	$ 286	$ 6,905	$ 6,487	$ 418

Three and Six Months Ended June 30, 2021 Compared to the Three and Six Months Ended June 30, 2020:

Current year revenue decreased due to fewer tons sold driven primarily by planned and unplanned outages at the Gillette, Wyoming energy complex. Operating expenses decreased primarily due to lower overburden costs, royalties and production taxes on decreased revenues.

Operating Statistics

The following table provides certain operating statistics for our Mining segment (in thousands, except for Revenue per ton):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Tons of coal sold	856	972	1,731	1,868
Cubic yards of overburden moved	1,609	2,211	3,431	4,478
Revenue per ton	$ 16.18	$ 15.27	$ 16.14	$ 15.66

Corporate and Other

Corporate and Other operating results were as follows (in thousands):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2021	2020	Variance	2021	2020	Variance
Adjusted operating income (loss)	$ (181)	$ (29)	$ (152)	$ (3,303)	$ 131	$ (3,434)

<u>Three Months Ended June 30, 2021 Compared to the Three Months Ended June 30, 2020:</u>

Adjusted operating income was comparable to the same period in the prior year.

<u>Six Months Ended June 30, 2021 Compared to the Six Months Ended June 30, 2020:</u>

The variance in Adjusted 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.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2021	2020	Variance	2021	2020	Variance
	(in thousands)					
Interest expense, net	$ (38,202)	$ (35,545)	$ (2,657)	$ (75,802)	$ (70,998)	$ (4,804)
Impairment of investment	—	—	$ —	$ —	$ (6,859)	$ 6,859
Other income (expense), net	(191)	(1,863)	$ 1,672	$ 75	$ 490	$ (415)
Income tax (expense)	(586)	(4,831)	$ 4,245	$ (1,080)	$ (20,833)	$ 19,753

<u>Three Months Ended June 30, 2021 Compared to the Three Months Ended June 30, 2020:</u>

Interest Expense

The increase in Interest expense, net was due to higher debt balances driven by the February 2021 term loan and the June 2020 senior unsecured notes partially offset by lower interest rates.

Other Income (Expense)

The decrease in Other (expense) was primarily due to lower non-service pension costs driven by a lower discount rate and lower costs for our non-qualified benefit plans which were driven by market performance.

Income Tax (Expense)

For the three months ended June 30, 2021, the effective tax rate was 2.0% compared to 16.4% for the same period in 2020. See Note 11 of the Notes to Condensed Consolidated Financial Statements for discussion of effective tax rate variances.

Six Months Ended June 30, 2021 Compared to the Six Months Ended June 30, 2020:

Interest Expense

The increase in Interest expense, net was due to higher debt balances driven by the February 2021 term loan and the June 2020 senior unsecured notes 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.

Income Tax (Expense)

For the six months ended June 30, 2021, the effective tax rate was 0.8% compared to 14.6% for the same period in 2020. See Note 11 of the Notes to Condensed Consolidated Financial Statements for discussion of effective tax rate variances.

Liquidity and Capital Resources

There have been no material changes in Liquidity and Capital Resources from those reported in Item 7 of our 2020 Annual Report on Form 10-K except as described below.

For the six months ended June 30, 2021, we did not experience significant impacts to our liquidity or financial condition due to the COVID-19 pandemic.

In response to the February 2021 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 above and in further detail in Note 5 of the Notes to Condensed Consolidated Financial Statements.

Cash Flow Activities

The following table summarizes our cash flows for the six months ended June 30, (in thousands):

Cash provided by (used in):		2021		2020		Variance
Operating activities	$	(250,173)	$	309,006	$	(559,179)
Investing activities	$	(309,737)	$	(349,725)	$	39,988
Financing activities	$	554,905	$	62,774	$	492,131

Six Months Ended June 30, 2021 Compared to the Six Months Ended June 30, 2020

Operating Activities:

Net cash provided by operating activities was $559 million lower than the same period in 2020. The variance to the prior year was primarily attributable to:

- Cash earnings (net income plus non-cash adjustments) were $13 million lower for the six months ended June 30, 2021 compared to the same period in the prior year primarily driven by higher operating expenses and higher interest expenses;

- Net inflows from changes in certain operating assets and liabilities were $556 million lower, primarily attributable to:
  - Cash outflows increased by $572 million as a result of changes in our regulatory assets and liabilities primarily driven by incremental costs from Winter Storm Uri;
  - Cash inflows increased by $12 million as a result of changes in accounts receivable and other current assets primarily driven by higher collections of accounts receivable; and
  - Cash outflows decreased by $3.4 million as a result of increases in accounts payable and accrued liabilities primarily driven by working capital requirements.
- Cash outflows decreased by $13 million due to pension contributions made in the prior year.
- Cash outflows increased by $1.7 million for other operating activities.

Investing Activities:

Net cash used in investing activities was $40 million lower than the same period in 2020. The variance to the prior year was primarily attributable to:

- Capital expenditures of $319 million for the six months ended June 30, 2021 compared to $348 million for the same period in the prior year. Lower current year expenditures are driven by lower programmatic safety, reliability and integrity spending at our Gas Utilities and Electric Utilities segments and the prior year Corriedale wind project at our Electric Utilities segment.
- Cash inflows increased by $11 million for other investing activities which was 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 $492 million higher than the same period in 2020. The variance to the prior year was primarily attributable to:

- Cash inflows increased $550 million due to short-term and long-term borrowings in excess of repayments. This increase was primarily driven by $600 million net borrowings from our term loan partially offset by prior year net proceeds from the June 17, 2020 debt transaction;
- Cash inflows decreased $59 million due to lower issuances of common stock;
- Cash outflows increased $4.7 million due to increased dividends paid on common stock; and
- Cash inflows increased by $6.8 million for other financing activities driven by the prior year financing costs incurred in the June 17, 2020 debt transaction.

Capital Sources

Term Loan

See Note 5 of the Notes to Condensed Consolidated Financial Statements for information relating to our term loan.

Revolving Credit Facility and CP Program

On July 19, 2021, we amended and restated our corporate Revolving Credit Facility under similar terms and conditions, See Note 5 of the Notes to Condensed Consolidated Financial Statements for more information.

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 June 30, 2021	Letters of Credit [(a)] at June 30, 2021	Available Capacity at June 30, 2021
Revolving Credit Facility and CP Program	July 19, 2026	$ 750	$ 230	$ 13	$ 507

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

The weighted average interest rate on short-term borrowings related to our Revolving Credit Facility and CP Program at June 30, 2021 was 0.19%. Short-term borrowing activity related to our Revolving Credit Facility and CP Program for the six months ended June 30, 2021 was:

	(dollars in millions)
Maximum amount outstanding (based on daily outstanding balances)	$ 311
Average amount outstanding (based on daily outstanding balances)	$ 200
Weighted average interest rates	0.23 %

Covenant Requirements

The Revolving Credit Facility and Wyoming Electric’s financing agreements contain covenant requirements. We were in compliance with these covenants as of June 30, 2021. See Note 5 of the Notes to Condensed Consolidated Financial Statements for more information.

Future Financing Plans

We will continue to assess debt and equity needs to support our capital investment plans and other key strategic objectives. In the second half of 2021, 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 an additional $60 million to $80 million of common stock under the ATM. As discussed in the Recent Developments above and in further detail in Note 5 of the Notes to Condensed Consolidated Financial Statements, on February 24, 2021, we entered into an $800 million term loan maturing on November 24, 2021. We repaid $200 million of this term loan in the first quarter of 2021. We expect to refinance a portion of the term loan with longer-term debt.

Credit Ratings

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.

The following table represents the credit ratings and outlook and risk profile of BHC at June 30, 2021:

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

(a) On April 10, 2020, S&P reported BBB+ rating and maintained a Stable outlook.
(b) On December 21, 2020, Moody’s reported Baa2 rating and maintained a Stable outlook.
(c) On August 20, 2020, Fitch reported BBB+ rating and maintained a Stable outlook.

The following table represents the credit ratings of South Dakota Electric at June 30, 2021:

Rating Agency	**Senior Secured Rating**
S&P [(a)]	A
Moody's [(b)]	A1
Fitch [(c)]	A

(a) On April 16, 2020, S&P reported A rating.
(b) On December 21, 2020, Moody's reported A1 rating.
(c) On August 20, 2020, Fitch reported A rating.

Capital Requirements

Capital Expenditures

	Actual	**Forecasted**				
Capital Expenditures by Segment	Six Months Ended June 30, 2021 (a)	2021 (b)	2022	2023	2024	2025
(in millions)						
Electric Utilities	$ 114	$ 240	$ 180	$ 143	$ 156	$ 154
Gas Utilities	179	377	347	339	330	326
Power Generation	7	10	9	6	4	5
Mining	2	9	9	9	9	10
Corporate and Other	3	11	5	13	13	13
Incremental Projects (c)	—	—	50	100	100	100
	$ 305	$ 647	$ 600	$ 610	$ 612	$ 608

(a) Includes accruals for property, plant and equipment as disclosed in supplemental cash flow information in the Condensed Consolidated Statements of Cash Flows in the Condensed Consolidated Financial Statements.
(b) Includes actual capital expenditures for the six months ended June 30, 2021.
(c) These represent projects that are being evaluated by our segments for timing, cost and other factors.

Dividends

Dividends paid on our common stock totaled $71 million for the six months ended June 30, 2021, or $0.565 per share per quarter. On July 26, 2021, our board of directors declared a quarterly dividend of $0.565 per share payable September 1, 2021, equivalent to an annual dividend of $2.26 per share. The amount of any future cash dividends to be declared and paid, if any, will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

Unconditional Purchase Obligations

See Note 3 of the Notes to Condensed Consolidated Financial Statements for recent updates to our purchase obligations.

Critical Accounting Policies Involving Significant Estimates

There have been no material changes in our critical accounting estimates from those reported in our 2020 Annual Report on Form 10-K. 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, cost recoverability through regulatory assets, impairment risk of goodwill and long-lived assets, valuation of pension assets and liabilities and contingent liabilities. For more information on our critical accounting estimates, see Part II, Item 7 of our 2020 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2020 Annual Report on Form 10-K and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations or cash flows.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes to our quantitative and qualitative disclosures about market risk previously disclosed in Item 7A of our Annual Report on Form 10-K.

ITEM 4. 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, as amended (the “Exchange Act”)) as of June 30, 2021. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at June 30, 2021.

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 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 June 30, 2021, there have been no changes in our internal controls over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see Note 3 in Item 8 of our 2020 Annual Report on Form 10-K and Note 3 in Item 1 of Part I of this Quarterly Report on Form 10-Q.

ITEM 1A. RISK FACTORS

There are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2020 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table contains monthly information about our acquisitions of equity securities for the three months ended June 30, 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
April 1, 2021 - April 30, 2021	2	$ 66.69	—	—
May 1, 2021 - May 31, 2021	805	$ 68.43	—	—
June 1, 2021 - June 30, 2021	1	$ 65.97	—	—
Total	808	$ 68.42	—	—

(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 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 Quarterly Report on Form 10-Q.

ITEM 6. EXHIBITS

Exhibits filed herewithin are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated.

Exhibit Number	Description
3.1	Restated Articles of Incorporation of the Registrant dated January 30, 2018 (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).
4.2	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).
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)

SIGNATURES

Pursuant to the requirements 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

/s/ Linden R. Evans
Linden R. Evans, President and
Chief Executive Officer

/s/ Richard W. Kinzley
Richard W. Kinzley, Senior Vice President and
Chief Financial Officer

Dated: August 4, 2021

Exhibit 31.1

CERTIFICATION

I, Linden R. Evans, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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: August 4, 2021

/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 Quarterly Report on Form 10-Q 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: August 4, 2021

/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 Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended June 30, 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: August 4, 2021

/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 Quarterly Report of Black Hills Corporation (the “Company”) on Form 10-Q for the period ended June 30, 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: August 4, 2021

/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 three month period ended June 30, 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 three months ended June 30, 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 three months ended June 30, 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	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 (#) (a)	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.