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

# FORM 10-Q

(mark one)

☒ **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: 1-10499**

# NORTHWESTERN CORP

**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware** | **46-0172280** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **3010 W. 69th Street Sioux Falls South Dakota** | **57108** |
| (Address of principal executive offices) | (Zip Code) |

**Registrant's telephone number, including area code: 605-978-2900**

**N/A**

**(Former name, former address and former fiscal year, if changed since last report)**

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 | NWE | Nasdaq Stock Market LLC |

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

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

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

Large Accelerated Filer ☒ Accelerated Filer ☐ Non-accelerated Filer ☐ Smaller Reporting Company ☐ Emerging Growth Company ☐

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

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

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

**Common Stock, Par Value $0.01, 51,561,227 shares outstanding at July 23, 2021**

**NORTHWESTERN CORPORATION**

**FORM 10-Q**

**INDEX**

## SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Quarterly Report on Form 10-Q regarding our assumptions, projections, expectations, targets, intentions or beliefs about future events. All statements other than statements of historical facts, included or incorporated by reference in this Quarterly Report, relating to management's current expectations of future financial performance, continued growth, changes in economic conditions or capital markets and changes in customer usage patterns and preferences are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934.

Words or phrases such as “anticipates,” “may,” “will,” “should,” “believes,” “estimates,” “expects,” “intends,” “plans,” “predicts,” “projects,” “targets,” “will likely result,” “will continue” or similar expressions identify forward-looking statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. We caution that while we make such statements in good faith and believe such statements are based on reasonable assumptions, including without limitation, management’s examination of historical operating trends, data contained in records and other data available from third parties, we cannot assure you that we will achieve our projections. Factors that may cause such differences include, but are not limited to:

- adverse determinations by regulators, as well as potential adverse federal, state, or local legislation or regulation, including costs of compliance with existing and future environmental requirements, could have a material effect on our liquidity, results of operations and financial condition;
- the impact of extraordinary external events, such as the COVID-19 pandemic, on our liquidity, results of operations and financial condition;
- changes in availability of trade credit, creditworthiness of counterparties, usage, commodity prices, fuel supply costs or availability due to higher demand, shortages, weather conditions, transportation problems or other developments, may reduce revenues or may increase operating costs, each of which could adversely affect our liquidity and results of operations;
- unscheduled generation outages or forced reductions in output, maintenance or repairs, which may reduce revenues and increase cost of sales or may require additional capital expenditures or other increased operating costs; and
- adverse changes in general economic and competitive conditions in the U.S. financial markets and in our service territories.

We have attempted to identify, in context, certain of the factors that we believe may cause actual future experience and results to differ materially from our current expectation regarding the relevant matter or subject area. In addition to the items specifically discussed above, our business and results of operations are subject to the uncertainties described under the caption “Risk Factors” which is part of the disclosure included in Part II, Item 1A of this Quarterly Report on Form 10-Q.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 10-K, 10-Q and 8-K, Proxy Statements on Schedule 14A, press releases, analyst and investor conference calls, and other communications released to the public. We believe that at the time made, the expectations reflected in all of these forward-looking statements are and will be reasonable. However, any or all of the forward-looking statements in this Quarterly Report on Form 10-Q, our reports on Forms 10-K and 8-K, our other reports on Form 10-Q, our Proxy Statements on Schedule 14A and any other public statements that are made by us may prove to be incorrect. This may occur as a result of assumptions, which turn out to be inaccurate, or as a consequence of known or unknown risks and uncertainties. Many factors discussed in this Quarterly Report on Form 10-Q, certain of which are beyond our control, will be important in determining our future performance. Consequently, actual results may differ materially from those that might be anticipated from forward-looking statements. In light of these and other uncertainties, you should not regard the inclusion of any of our forward-looking statements in this Quarterly Report on Form 10-Q or other public communications as a representation by us that our plans and objectives will be achieved, and you should not place undue reliance on such forward-looking statements.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. However, your attention is directed to any further disclosures made on related subjects in our subsequent reports filed with the Securities and Exchange Commission (SEC) on Forms 10-K, 10-Q and 8-K and Proxy Statements on Schedule 14A.

***Unless the context requires otherwise, references to “we,” “us,” “our,” “NorthWestern Corporation,” “NorthWestern Energy,” and “NorthWestern” refer specifically to NorthWestern Corporation and its subsidiaries.***

## PART 1. FINANCIAL INFORMATION

### ITEM 1. FINANCIAL STATEMENTS

### NORTHWESTERN CORPORATION

### CONDENSED CONSOLIDATED STATEMENTS OF INCOME

**(Unaudited)**

**(in thousands, except per share amounts)**

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| Revenues | | | | |
| Electric | $ 241,440 | $ 217,938 | $ 511,511 | $ 462,563 |
| Gas | 56,777 | 51,422 | 187,509 | 142,052 |
| **Total Revenues** | 298,217 | 269,360 | 699,020 | 604,615 |
| Operating Expenses | | | | |
| Cost of sales | 67,965 | 61,043 | 212,478 | 152,315 |
| Operating, general and administrative | 77,113 | 71,715 | 157,965 | 150,720 |
| Property and other taxes | 47,287 | 46,981 | 94,765 | 91,480 |
| Depreciation and depletion | 46,809 | 44,782 | 93,784 | 90,047 |
| **Total Operating Expenses** | 239,174 | 224,521 | 558,992 | 484,562 |
| Operating Income | 59,043 | 44,839 | 140,028 | 120,053 |
| Interest Expense, net | (23,473) | (24,287) | (46,983) | (48,621) |
| Other Income (Expense), net | 3,032 | 224 | 8,606 | (1,758) |
| Income Before Income Taxes | 38,602 | 20,776 | 101,651 | 69,674 |
| Income Tax (Expense) Benefit | (1,365) | 718 | (1,343) | 2,524 |
| **Net Income** | $ 37,237 | $ 21,494 | $ 100,308 | $ 72,198 |
| | | | | |
| Average Common Shares Outstanding | 50,989 | 50,570 | 50,811 | 50,538 |
| Basic Earnings per Average Common Share | $ 0.72 | $ 0.43 | $ 1.97 | $ 1.43 |
| Diluted Earnings per Average Common Share | $ 0.72 | $ 0.43 | $ 1.96 | $ 1.43 |
| Dividends Declared per Common Share | $ 0.62 | $ 0.60 | $ 1.24 | $ 1.20 |

See Notes to Condensed Consolidated Financial Statements

## NORTHWESTERN CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

**(Unaudited)**

**(in thousands)**

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Net Income | $ 37,237 | $ 21,494 | $ 100,308 | $ 72,198 |
| Other comprehensive income, net of tax: | | | | |
| Foreign currency translation adjustment | 21 | (8) | (55) | 93 |
| Postretirement medical liability adjustment | (159) | — | (317) | — |
| Reclassification of net losses on derivative instruments | 113 | 113 | 226 | 226 |
| Total Other Comprehensive (Loss) Income | (25) | 105 | (146) | 319 |
| **Comprehensive Income** | $ 37,212 | $ 21,599 | $ 100,162 | $ 72,517 |

See Notes to Condensed Consolidated Financial Statements

## NORTHWESTERN CORPORATION

## CONDENSED CONSOLIDATED BALANCE SHEETS

**(Unaudited)**

**(in thousands, except share data)**

| | June 30, 2021 | December 31, 2020 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets:** | | |
| Cash and cash equivalents | $ 5,942 | $ 5,811 |
| Restricted cash | 13,656 | 11,285 |
| Accounts receivable, net | 143,497 | 168,229 |
| Inventories | 69,946 | 61,010 |
| Regulatory assets | 95,326 | 44,973 |
| Prepaid expenses and other | 19,365 | 17,372 |
| **Total current assets** | **347,732** | **308,680** |
| Property, plant, and equipment, net | 5,071,826 | 4,952,935 |
| Goodwill | 357,586 | 357,586 |
| Regulatory assets | 724,575 | 701,444 |
| Other noncurrent assets | 64,521 | 68,804 |
| **Total Assets** | **$ 6,566,240** | **$ 6,389,449** |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities:** | | |
| Current maturities of finance leases | $ 2,768 | $ 2,668 |
| Short term borrowings | — | 100,000 |
| Accounts payable | 89,622 | 100,388 |
| Accrued expenses | 230,444 | 207,514 |
| Regulatory liabilities | 25,618 | 55,853 |
| **Total current liabilities** | **348,452** | **466,423** |
| Long-term finance leases | 13,388 | 14,771 |
| Long-term debt | 2,503,347 | 2,315,261 |
| Deferred income taxes | 494,477 | 471,777 |
| Noncurrent regulatory liabilities | 631,127 | 631,419 |
| Other noncurrent liabilities | 398,134 | 410,703 |
| **Total Liabilities** | **4,388,925** | **4,310,354** |
| Commitments and Contingencies (Note 10) | | |
| **Shareholders' Equity:** | | |
| Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 55,117,575 and 51,560,013 shares, respectively; Preferred stock, par value 0.01; authorized 50,000,000 shares; none issued | 551 | 541 |
| Treasury stock at cost | (98,578) | (98,075) |
| Paid-in capital | 1,575,159 | 1,513,787 |
| Retained earnings | 707,598 | 670,111 |
| Accumulated other comprehensive loss | (7,415) | (7,269) |
| **Total Shareholders' Equity** | **2,177,315** | **2,079,095** |
| **Total Liabilities and Shareholders' Equity** | **$ 6,566,240** | **$ 6,389,449** |

See Notes to Condensed Consolidated Financial Statements

## NORTHWESTERN CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

**(Unaudited)**

**(in thousands)**

| | Six Months Ended June 30, 2021 | Six Months Ended June 30, 2020 |
|---|---|---|
| **OPERATING ACTIVITIES:** | | |
| Net income | $ 100,308 | $ 72,198 |
| Items not affecting cash: | | |
| Depreciation and depletion | 93,784 | 90,047 |
| Amortization of debt issuance costs, discount and deferred hedge gain | 2,637 | 2,371 |
| Stock-based compensation costs | 4,538 | 4,195 |
| Equity portion of allowance for funds used during construction | (4,562) | (2,318) |
| (Gain) loss on disposition of assets | (55) | 3 |
| Deferred income taxes | (641) | — |
| Changes in current assets and liabilities: | | |
| Accounts receivable | 24,732 | 42,301 |
| Inventories | (8,936) | (7,299) |
| Other current assets | (1,994) | 570 |
| Accounts payable | (15,042) | (7,319) |
| Accrued expenses | 22,828 | 9,382 |
| Regulatory assets | (50,353) | 6,912 |
| Regulatory liabilities | (30,235) | 12,365 |
| Other noncurrent assets | (3,800) | (346) |
| Other noncurrent liabilities | (28,689) | (3,843) |
| **Cash Provided by Operating Activities** | **104,520** | **219,219** |
| **INVESTING ACTIVITIES:** | | |
| Property, plant, and equipment additions | (182,194) | (176,482) |
| Investment in equity securities | (646) | (37) |
| **Cash Used in Investing Activities** | **(182,840)** | **(176,519)** |
| **FINANCING ACTIVITIES:** | | |
| Treasury stock activity | 32 | (2,076) |
| Proceeds from issuance of common stock, net | 56,311 | — |
| Dividends on common stock | (62,821) | (60,172) |
| Issuance of long-term debt, net | 99,915 | 150,000 |
| Line of credit borrowings (repayments), net | 88,000 | (225,000) |
| (Repayments) issuance of short-term borrowings | (100,000) | 100,000 |
| Financing costs | (615) | (1,109) |
| **Cash Provided by (Used in) Financing Activities** | **80,822** | **(38,357)** |
| **Increase in Cash, Cash Equivalents, and Restricted Cash** | 2,502 | 4,343 |
| Cash, Cash Equivalents, and Restricted Cash, beginning of period | 17,096 | 12,070 |
| **Cash, Cash Equivalents, and Restricted Cash, end of period** | **$ 19,598** | **$ 16,413** |
| **Supplemental Cash Flow Information:** | | |
| Cash paid during the period for: | | |
| Income taxes | $ 1,960 | $ 55 |
| Interest | 43,474 | 42,115 |
| Significant non-cash transactions: | | |
| Capital expenditures included in accounts payable | 25,955 | 13,835 |

See Notes to Condensed Consolidated Financial Statements

## NORTHWESTERN CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

**(Unaudited)**

**(in thousands, except per share data)**

| | Three Months Ended June 30, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Number of Common Shares | Number of Treasury Shares | Common Stock | Treasury Stock | Paid in Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Total Shareholders' Equity |
| **Balance at March 31, 2020** | **54,145** | **3,578** | **$ 541** | **$ (98,644)** | **$1,512,148** | **$ 655,865** | **$ (9,434)** | **$ 2,060,476** |
| Net income | — | — | — | — | — | 21,494 | — | 21,494 |
| Foreign currency translation adjustment, net of tax | — | — | — | — | — | — | (8) | (8) |
| Reclassification of net losses on derivative instruments from OCI to net income, net of tax | — | — | — | — | — | — | 113 | 113 |
| Stock-based compensation | — | — | — | — | 1,139 | — | — | 1,139 |
| Issuance of shares | — | (7) | — | 206 | 223 | — | — | 429 |
| Dividends on common stock ($0.600 per share) | — | — | — | — | — | (30,087) | — | (30,087) |
| **Balance at June 30, 2020** | **54,145** | **3,571** | **$ 541** | **$ (98,438)** | **$1,513,510** | **$ 647,272** | **$ (9,329)** | **$ 2,053,556** |
| | | | | | | | | |
| **Balance at March 31, 2021** | **54,238** | **3,563** | **$ 542** | **$ (98,730)** | **$1,517,355** | **$ 702,058** | **$ (7,390)** | **$ 2,113,835** |
| Net income | — | — | — | — | — | 37,237 | — | 37,237 |
| Foreign currency translation adjustment, net of tax | — | — | — | — | — | — | 21 | 21 |
| Reclassification of net losses on derivative instruments from OCI to net income, net of tax | — | — | — | — | — | — | 113 | 113 |
| Postretirement medical liability adjustment, net of tax | — | — | — | — | — | — | (159) | (159) |
| Stock-based compensation | — | — | — | — | 1,299 | — | — | 1,299 |
| Issuance of shares | 880 | (5) | 9 | 152 | 56,505 | — | — | 56,666 |
| Dividends on common stock ($0.620 per share) | — | — | — | — | — | (31,697) | — | (31,697) |
| **Balance at June 30, 2021** | **55,118** | **3,558** | **$ 551** | **$ (98,578)** | **$1,575,159** | **$ 707,598** | **$ (7,415)** | **$ 2,177,315** |

| | Six Months Ended June 30, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Number of Common Shares | Number of Treasury Shares | Common Stock | Treasury Stock | Paid in Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Total Shareholders' Equity |
| **Balance at December 31, 2019** | **53,999** | **3,547** | **$ 541** | **$ (96,015)** | **$ 1,508,970** | **$ 635,246** | **$ (9,648)** | **$ 2,039,094** |
| Net income | — | — | — | — | — | 72,198 | — | 72,198 |
| Foreign currency translation adjustment, net of tax | — | — | — | — | — | — | 93 | 93 |
| Reclassification of net losses on derivative instruments from OCI to net income, net of tax | — | — | — | — | — | — | 226 | 226 |
| Stock-based compensation | 146 | 35 | — | (2,740) | 4,170 | — | — | 1,430 |
| Issuance of shares | — | (11) | — | 317 | 370 | — | — | 687 |
| Dividends on common stock ($1.200 per share) | — | — | — | — | — | (60,172) | — | (60,172) |
| **Balance at June 30, 2020** | **54,145** | **3,571** | **$ 541** | **$ (98,438)** | **$ 1,513,510** | **$ 647,272** | **$ (9,329)** | **$ 2,053,556** |
| | | | | | | | | |
| **Balance at December 31, 2020** | **54,145** | **3,558** | **$ 541** | **$ (98,075)** | **$ 1,513,787** | **$ 670,111** | **$ (7,269)** | **$ 2,079,095** |
| Net income | — | — | — | — | — | 100,308 | — | 100,308 |
| Foreign currency translation adjustment, net of tax | — | — | — | — | — | — | (55) | (55) |
| Reclassification of net losses on derivative instruments from OCI to net income, net of tax | — | — | — | — | — | — | 226 | 226 |
| Postretirement medical liability adjustment, net of tax | — | — | — | — | — | — | (317) | (317) |
| Stock-based compensation | 93 | 17 | 1 | (970) | 4,510 | — | — | 3,541 |
| Issuance of shares | 880 | (17) | 9 | 467 | 56,862 | — | — | 57,338 |
| Dividends on common stock ($1.240 per share) | — | — | — | — | — | (62,821) | — | (62,821) |
| Balance at June 30, 2021 | **55,118** | **3,558** | **$ 551** | **$ (98,578)** | **$ 1,575,159** | **$ 707,598** | **$ (7,415)** | **$ 2,177,315** |

See Notes to Condensed Consolidated Financial Statements

# NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
**(Reference is made to Notes to Financial Statements included in NorthWestern Corporation's Annual Report)**
**(Unaudited)**

## (1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 743,000 customers in Montana, South Dakota, Nebraska and Yellowstone National Park.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates. The unaudited Condensed Consolidated Financial Statements (Financial Statements) reflect all adjustments (which unless otherwise noted are normal and recurring in nature) that are, in the opinion of management, necessary to fairly present our financial position, results of operations and cash flows. The actual results for the interim periods are not necessarily indicative of the operating results to be expected for a full year or for other interim periods. Events occurring subsequent to June 30, 2021 have been evaluated as to their potential impact to the Financial Statements through the date of issuance.

The Financial Statements included herein have been prepared by NorthWestern, without audit, pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations; however, management believes that the condensed disclosures provided are adequate to make the information presented not misleading. Management recommends that these Financial Statements be read in conjunction with the audited financial statements and related footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2020.

### Reclassification

In the fourth quarter of 2020, we changed our classification of excess deferred income taxes in the Consolidated Balance Sheets from a regulatory asset to a regulatory liability, such that the excess deferred income tax regulatory liabilities are reflected on a gross basis, rather than net within our income tax regulatory asset based on our right to offset. The impact to our Consolidated Statements of Cash Flows for the six months ended June 30, 2020 is a gross up of non-cash activity within the Other noncurrent assets and Other noncurrent liabilities captions, both within the operating activities section, that offset one another with no impact to cash provided by operating activities. The impact to the total assets reported as of June 30, 2020 in the segment information table within Note 6 - Segment Information was an increase of $169.4 million. This reclassification had no effect on previously reported Net income in our Condensed Consolidated Statements of Income, Condensed Consolidated Statements of Comprehensive Income, and Condensed Consolidated Statements of Shareholders' Equity.

### Variable Interest Entities

A reporting company is required to consolidate a variable interest entity (VIE) as its primary beneficiary, which means it has a controlling financial interest, when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. An entity is considered to be a VIE when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance.

Certain long-term purchase power and tolling contracts may be considered variable interests. We have various long-term purchase power contracts with other utilities and certain qualifying co-generation facilities and qualifying small power production facilities (QF). We identified one QF contract that may constitute a VIE. We entered into a 40-year power purchase contract in 1984 with this 35 megawatt (MW) coal-fired QF to purchase substantially all of the facility's capacity and electrical output over a substantial portion of its estimated useful life. We absorb a portion of the facility's variability through annual changes to the price we pay per megawatt hour (MWH). After making exhaustive efforts, we have been unable to obtain the information from the facility necessary to determine whether the facility is a VIE or whether we are the primary beneficiary of the facility. The contract with the facility contains no provision which legally obligates the facility to release this information. We have accounted for this QF contract as an executory contract. Based on the current contract terms with this QF, as of June 30, 2021 our estimated remaining gross contractual payments aggregate approximately $80.7 million through 2024.

## Supplemental Cash Flow Information

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Condensed Consolidated Balance Sheets that sum to the total of the same such amounts shown in the Condensed Consolidated Statements of Cash Flows (in thousands):

| | June 30, 2021 | December 31, 2020 | June 30, 2020 | December 31, 2019 |
|---|---|---|---|---|
| Cash and cash equivalents | $ 5,942 | $ 5,811 | $ 7,464 | $ 5,145 |
| Restricted cash | 13,656 | 11,285 | 8,949 | 6,925 |
| **Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows** | $ 19,598 | $ 17,096 | $ 16,413 | $ 12,070 |

## Goodwill

We completed our annual goodwill impairment test as of April 1, 2021 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

## (2) Regulatory Matters

### FERC Filing - Montana Transmission Service Rates

In May 2019, we submitted a filing with the Federal Energy Regulatory Commission (FERC) for our Montana transmission assets. In June 2019, the FERC issued an order accepting our filing, and granting interim rates (subject to refund) effective July 1, 2019. In November 2020, we filed a settlement and implemented settlement rates on December 1, 2020. In January 2021, the FERC approved our settlement and during the first quarter of 2021 we refunded approximately $20.5 million to our FERC regulated wholesale customers.

Revenues from FERC regulated wholesale customers associated with our Montana FERC assets are reflected in our Montana Public Service Commission (MPSC) jurisdictional rates as a credit to retail customers. In March 2021, we submitted a compliance filing with the MPSC adjusting the revenue credit in our Montana retail rates to reflect the FERC approved settlement rates and a refund to retail customers of the difference between the FERC interim rates and the FERC approved settlement rates that were collected during the period from July 1, 2019 through March 31, 2021. On May 19, 2021, the MPSC approved the proposed tariffs and rates on a final basis. During the three month period ended June 30, 2021, we recognized a $4.7 million favorable adjustment related to excess deferred revenues based on the final MPSC approval. As of June 30, 2021, we had cumulative deferred revenue of approximately $6.1 million.

### Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2020, approximately 65 MW of CREPs. While we have made progress towards meeting this obligation by acquiring approximately 50 MW of CREPs, we have been unable to acquire the remaining MWs required for various reasons, including the fact that proposed projects fail to qualify as CREPs or do not meet the statutory cost cap. The MPSC granted us waivers for 2012 through 2016. The validity of the MPSC’s action as it related to waivers granted for 2015 and 2016 has been challenged legally and we are waiting on a final decision from the Montana Supreme Court.

On May 14, 2021, the Montana Governor signed a bill that repealed the CREP requirement. We notified the Montana Supreme Court of the repeal as it considers the legal challenge concerning the MPSC's decision granting our waiver requests from full compliance for years 2015 and 2016. We also dismissed our pending application filed with the MPSC for a waiver from full compliance for years 2017 through 2020. If the Montana Supreme Court and/or MPSC determine that the repeal should not be applied retroactively and find that waivers should not be granted, we could be liable for penalties. However, we do not believe any such penalties would be material.

## (3) Income Taxes

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate due to the regulatory impact of flowing through the federal and state tax benefit of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (in thousands):

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2021 | | 2020 | |
| Income Before Income Taxes | $ 38,602 | | $ 20,776 | |
| Income tax calculated at federal statutory rate | 8,107 | 21.0 % | 4,363 | 21.0 % |
| Permanent or flow-through adjustments: | | | | |
| State income tax, net of federal provisions | 222 | 0.6 | 5 | 0.0 |
| Flow-through repairs deductions | (4,227) | (11.0) | (3,208) | (15.4) |
| Production tax credits | (2,262) | (5.9) | (1,737) | (8.5) |
| Plant and depreciation of flow-through items | (184) | (0.5) | 59 | 0.3 |
| Amortization of excess deferred income tax | (143) | (0.4) | (153) | (0.7) |
| Other, net | (148) | (0.4) | (47) | (0.2) |
| | (6,742) | (17.6) | (5,081) | (24.5) |
| **Income tax expense (benefit)** | $ 1,365 | 3.4 % | $ (718) | (3.5)% |

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2021 | | 2020 | |
| Income Before Income Taxes | $ 101,651 | | $ 69,674 | |
| Income tax calculated at federal statutory rate | 21,347 | 21.0 % | 14,631 | 21.0 % |
| Permanent or flow through adjustments: | | | | |
| State income, net of federal provisions | 277 | 0.3 | 27 | 0.1 |
| Flow-through repairs deductions | (12,080) | (11.9) | (10,646) | (15.3) |
| Production tax credits | (6,569) | (6.5) | (5,348) | (7.7) |
| Plant and depreciation of flow through items | (524) | (0.5) | 196 | 0.3 |
| Amortization of excess deferred income tax | (408) | (0.4) | (509) | (0.7) |
| Share-based compensation | (261) | (0.3) | (609) | (0.9) |
| Other, net | (439) | (0.4) | (266) | (0.4) |
| | (20,004) | (19.7) | (17,155) | (24.6) |
| **Income tax expense (benefit)** | $ 1,343 | 1.3 % | $ (2,524) | (3.6)% |

### Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. We had unrecognized tax benefits of approximately $32.6 million as of June 30, 2021, including approximately $27.9 million that, if recognized, would impact our effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As of June 30, 2021, we did not have any amounts accrued for the payment of interest and penalties.

Tax years 2017 and forward remain subject to examination by the Internal Revenue Service (IRS) and state taxing authorities. In addition, the available federal net operating loss carryforward may be reduced by the IRS for losses originating in certain tax years from 2003 forward.

## (4) Comprehensive (Loss) Income

The following tables display the components of Other Comprehensive (Loss) Income, after-tax, and the related tax effects (in thousands):

| | Three Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | June 30, 2021 | | | June 30, 2020 | | |
| | Before-Tax Amount | Tax Expense | Net-of-Tax Amount | Before-Tax Amount | Tax Expense | Net-of-Tax Amount |
| Foreign currency translation adjustment | $ 21 | $ — | $ 21 | $ (8) | $ — | $ (8) |
| Reclassification of net income on derivative instruments | 153 | (40) | 113 | 153 | (40) | 113 |
| Postretirement medical liability adjustment | (212) | 53 | (159) | — | — | — |
| Other comprehensive (loss) income | $ (38) | $ 13 | $ (25) | $ 145 | $ (40) | $ 105 |

| | Six Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | June 30, 2021 | | | June 30, 2020 | | |
| | Before-Tax Amount | Tax Expense | Net-of-Tax Amount | Before-Tax Amount | Tax Expense | Net-of-Tax Amount |
| Foreign currency translation adjustment | $ (55) | $ — | $ (55) | $ 93 | $ — | $ 93 |
| Reclassification of net income on derivative instruments | 306 | (80) | 226 | 306 | (80) | 226 |
| Postretirement medical liability adjustment | (424) | 107 | (317) | — | — | — |
| Other comprehensive (loss) income | $ (173) | $ 27 | $ (146) | $ 399 | $ (80) | $ 319 |

Balances by classification included within accumulated other comprehensive loss (AOCL) on the Condensed Consolidated Balance Sheets are as follows, net of tax (in thousands):

| | June 30, 2021 | December 31, 2020 |
|---|---|---|
| Foreign currency translation | $ 1,445 | $ 1,500 |
| Derivative instruments designated as cash flow hedges | (10,503) | (10,729) |
| Postretirement medical plans | 1,643 | 1,960 |
| Accumulated other comprehensive loss | $ (7,415) | $ (7,269) |

The following tables display the changes in AOCL by component, net of tax (in thousands):

| | Affected Line Item in the Condensed Consolidated Statements of Income | Three Months Ended June 30, 2021 | | | |
|---|---|---|---|---|---|
| | | Interest Rate Derivative Instruments Designated as Cash Flow Hedges | Postretirement Medical Plans | Foreign Currency Translation | Total |
| Beginning balance | | $ (10,616) | $ 1,802 | $ 1,424 | $ (7,390) |
| Other comprehensive income before reclassifications | | — | — | 21 | 21 |
| Amounts reclassified from AOCL | Interest Expense | 113 | — | — | 113 |
| Amounts reclassified from AOCL | | — | (159) | — | (159) |
| Net current-period other comprehensive income (loss) | | 113 | (159) | 21 | (25) |
| Ending balance | | $ (10,503) | $ 1,643 | $ 1,445 | $ (7,415) |

| | Affected Line Item in the Condensed Consolidated Statements of Income | Three Months Ended June 30, 2020 | | | |
|---|---|---|---|---|---|
| | | Interest Rate Derivative Instruments Designated as Cash Flow Hedges | Postretirement Medical Plans | Foreign Currency Translation | Total |
| Beginning balance | | $ (11,068) | $ 120 | $ 1,514 | $ (9,434) |
| Other comprehensive loss before reclassifications | | — | — | (8) | (8) |
| Amounts reclassified from AOCL | Interest Expense | 113 | — | — | 113 |
| Net current-period other comprehensive income (loss) | | 113 | — | (8) | 105 |
| Ending balance | | $ (10,955) | $ 120 | $ 1,506 | $ (9,329) |

| | Affected Line Item in the Condensed Consolidated Statements of Income | Six Months Ended June 30, 2021 | | | |
|---|---|---|---|---|---|
| | | Interest Rate Derivative Instruments Designated as Cash Flow Hedges | Pension and Postretirement Medical Plans | Foreign Currency Translation | Total |
| Beginning balance | | $ (10,729) | $ 1,960 | $ 1,500 | $ (7,269) |
| Other comprehensive loss before reclassifications | | — | — | (55) | (55) |
| Amounts reclassified from AOCL | Interest Expense | 226 | — | — | 226 |
| Amounts reclassified from AOCL | | — | (317) | — | (317) |
| Net current-period other comprehensive income (loss) | | 226 | (317) | (55) | (146) |
| Ending balance | | $ (10,503) | $ 1,643 | $ 1,445 | $ (7,415) |

| | Affected Line Item in the Condensed Consolidated Statements of Income | Six Months Ended June 30, 2020 Interest Rate Derivative Instruments Designated as Cash Flow Hedges | Pension and Postretirement Medical Plans | Foreign Currency Translation | Total |
|---|---|---|---|---|---|
| Beginning balance | | $ (11,181) | $ 120 | $ 1,413 | $ (9,648) |
| Other comprehensive income before reclassifications | | — | — | 93 | 93 |
| Amounts reclassified from AOCL | Interest Expense | 226 | — | — | 226 |
| Net current-period other comprehensive income | | 226 | — | 93 | 319 |
| Ending balance | | $ (10,955) | $ 120 | $ 1,506 | $ (9,329) |

### (5) Financing Activities

In March 2021, we issued and sold $100.0 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 1.00% maturing on March 26, 2024. The net proceeds were used to repay in full our outstanding $100.0 million term loan that was due April 2, 2021. We may redeem some or all of the bonds at any time in whole, or from time to time in part, at our option, on or after March 26, 2022, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed, plus accrued and unpaid interest on the principal amount of the bonds being redeemed to, but excluding, the redemption date. The bonds are secured by our electric and natural gas assets in Montana and Wyoming.

In April 2021, we entered into an Equity Distribution Agreement with BofA Securities, Inc., CIBC World Markets Corp, Credit Suisse Securities (USA) LLC, and J.P. Morgan Securities LLC, collectively the sales agents, pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an At-the-Market (ATM) offering program, including an equity forward sales component. During the three months ended June 30, 2021, we issued 879,309 shares of our common stock under the ATM program at an average price of $64.91, for net proceeds of $56.3 million, which is net of sales commissions and other fees paid of approximately $0.8 million.

### (6) Segment Information

Our reportable business segments are primarily engaged in the electric and natural gas business. The remainder of our operations are presented as other, which primarily consists of unallocated corporate costs and unregulated activity.

We evaluate the performance of these segments based on gross margin. The accounting policies of the operating segments are the same as the parent except that the parent allocates some of its operating expenses to the operating segments according to a methodology designed by management for internal reporting purposes and involves estimates and assumptions.

Financial data for the business segments are as follows (in thousands):

| Three Months Ended June 30, 2021 | Electric | Gas | Other | Eliminations | Total |
|---|---|---|---|---|---|
| Operating revenues | $ 241,440 | $ 56,777 | $ — | $ — | $ 298,217 |
| Cost of sales | 49,239 | 18,726 | — | — | 67,965 |
| Gross margin | 192,201 | 38,051 | — | — | 230,252 |
| Operating, general and administrative | 58,035 | 19,265 | (187) | — | 77,113 |
| Property and other taxes | 36,957 | 10,328 | 2 | — | 47,287 |
| Depreciation and depletion | 38,540 | 8,269 | — | — | 46,809 |
| Operating income | 58,669 | 189 | 185 | — | 59,043 |
| Interest expense, net | (20,849) | (1,422) | (1,202) | — | (23,473) |
| Other income (expense), net | 2,215 | 1,036 | (219) | — | 3,032 |
| Income tax expense | (804) | (208) | (353) | — | (1,365) |
| Net income (loss) | $ 39,231 | $ (405) | $ (1,589) | $ — | $ 37,237 |
| Total assets | $ 5,281,173 | $ 1,279,923 | $ 5,144 | $ — | $ 6,566,240 |
| Capital expenditures | $ 82,460 | $ 21,880 | $ — | $ — | $ 104,340 |

| Three Months Ended June 30, 2020 | Electric | Gas | Other | Eliminations | Total |
|---|---|---|---|---|---|
| Operating revenues | $ 217,938 | $ 51,422 | $ — | $ — | $ 269,360 |
| Cost of sales | 48,305 | 12,738 | — | — | 61,043 |
| Gross margin | 169,633 | 38,684 | — | — | 208,317 |
| Operating, general and administrative | 53,599 | 18,988 | (872) | — | 71,715 |
| Property and other taxes | 36,811 | 10,167 | 3 | — | 46,981 |
| Depreciation and depletion | 36,846 | 7,936 | — | — | 44,782 |
| Operating income | 42,377 | 1,593 | 869 | — | 44,839 |
| Interest expense, net | (21,483) | (1,646) | (1,158) | — | (24,287) |
| Other income (expense), net | 959 | 309 | (1,044) | — | 224 |
| Income tax benefit (expense) | 756 | (337) | 299 | — | 718 |
| Net income (loss) | $ 22,609 | $ (81) | $ (1,034) | $ — | $ 21,494 |
| Total assets[(1)] | $ 4,947,183 | $ 1,189,460 | $ 4,568 | $ — | $ 6,141,211 |
| Capital expenditures | $ 79,744 | $ 18,367 | $ — | $ — | $ 98,111 |

| Six Months Ended June 30, 2021 | Electric | Gas | Other | Eliminations | Total |
|---|---|---|---|---|---|
| Operating revenues | $ 511,511 | $ 187,509 | $ — | $ — | $ 699,020 |
| Cost of sales | 129,427 | 83,051 | — | — | 212,478 |
| Gross margin | 382,084 | 104,458 | — | — | 486,542 |
| Operating, general and administrative | 115,790 | 40,444 | 1,731 | — | 157,965 |
| Property and other taxes | 73,984 | 20,777 | 4 | — | 94,765 |
| Depreciation and depletion | 77,224 | 16,560 | — | — | 93,784 |
| Operating income (loss) | 115,086 | 26,677 | (1,735) | — | 140,028 |
| Interest expense, net | (41,578) | (2,910) | (2,495) | — | (46,983) |
| Other income | 5,044 | 2,019 | 1,543 | — | 8,606 |
| Income tax (expense) benefit | (689) | (2,230) | 1,576 | — | (1,343) |
| Net income (loss) | $ 77,863 | $ 23,556 | $ (1,111) | $ — | $ 100,308 |
| Total assets | $ 5,281,173 | $ 1,279,923 | $ 5,144 | $ — | $ 6,566,240 |
| Capital expenditures | $ 151,400 | $ 30,794 | $ — | $ — | $ 182,194 |

| Six Months Ended June 30, 2020 | Electric | Gas | Other | Eliminations | Total |
|---|---|---|---|---|---|
| Operating revenues | $ 462,563 | $ 142,052 | $ — | $ — | $ 604,615 |
| Cost of sales | 112,139 | 40,176 | — | — | 152,315 |
| Gross margin | 350,424 | 101,876 | — | — | 452,300 |
| Operating, general and administrative | 112,487 | 41,289 | (3,056) | — | 150,720 |
| Property and other taxes | 71,547 | 19,928 | 5 | — | 91,480 |
| Depreciation and depletion | 74,022 | 16,025 | — | — | 90,047 |
| Operating income | 92,368 | 24,634 | 3,051 | — | 120,053 |
| Interest expense, net | (42,299) | (3,250) | (3,072) | — | (48,621) |
| Other (expense) income | 1,572 | 404 | (3,734) | — | (1,758) |
| Income tax (expense) benefit | 1,412 | (1,074) | 2,186 | — | 2,524 |
| Net income (loss) | $ 53,053 | $ 20,714 | $ (1,569) | $ — | $ 72,198 |
| Total assets[(1)] | $ 4,947,183 | $ 1,189,460 | $ 4,568 | $ — | $ 6,141,211 |
| Capital expenditures | $ 143,092 | $ 33,390 | $ — | $ — | $ 176,482 |

(1) Subsequent to the issuance of our Annual Report on Form 10-K for the year ended December 31, 2020, we determined that Total Assets - Electric and Total Assets - Gas had been incorrectly reported due to an error in the allocation methodology utilized to calculate assets by segment. As a result the June 30, 2020 Total Assets - Electric and Total Assets - Gas amounts have been corrected from the amounts previously reported to reflect an increase of Total Assets - Electric and a decrease of Total Assets - Gas of $457.8 million. The correction had no impact on net income or the presentation of total assets on the consolidated balance sheets and was determined not to be material.

## (7) Revenue from Contracts with Customers

### Nature of Goods and Services

We provide retail electric and natural gas services to three primary customer classes. Our residential customers include single private dwellings and individual apartments. Our commercial customers consist primarily of main street businesses, and our industrial customers consist primarily of manufacturing and processing businesses that turn raw materials into products.

***Electric Segment -*** Our regulated electric utility business primarily provides generation, transmission, and distribution services to customers in our Montana and South Dakota jurisdictions. We recognize revenue when electricity is delivered to the customer. Payments on our tariff based sales are generally due 20-30 days after the billing date.

***Natural Gas Segment -*** Our regulated natural gas utility business primarily provides production, storage, transmission, and distribution services to customers in our Montana, South Dakota, and Nebraska jurisdictions. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff based sales are generally due 20-30 days after the billing date.

### Disaggregation of Revenue

The following tables disaggregate our revenue by major source and customer class (in millions):

| | Three Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | June 30, 2021 | | | June 30, 2020 | | |
| | Electric | Natural Gas | Total | Electric | Natural Gas | Total |
| Montana | $ 69.9 | $ 25.5 | $ 95.4 | $ 70.6 | $ 17.5 | $ 88.1 |
| South Dakota | 14.4 | 6.4 | 20.8 | 14.6 | 4.7 | 19.3 |
| Nebraska | — | 3.9 | 3.9 | — | 3.5 | 3.5 |
| **Residential** | **84.3** | **35.8** | **120.1** | **85.2** | **25.7** | **110.9** |
| Montana | 84.6 | 13.0 | 97.6 | 77.4 | 8.2 | 85.6 |
| South Dakota | 24.1 | 4.3 | 28.4 | 23.2 | 2.9 | 26.1 |
| Nebraska | — | 1.8 | 1.8 | — | 1.5 | 1.5 |
| **Commercial** | **108.7** | **19.1** | **127.8** | **100.6** | **12.6** | **113.2** |
| Industrial | 9.2 | 0.2 | 9.4 | 9.2 | 0.1 | 9.3 |
| Lighting, Governmental, Irrigation, and Interdepartmental | 9.1 | 0.4 | 9.5 | 9.2 | 0.3 | 9.5 |
| **Total Customer Revenues** | **211.3** | **55.5** | **266.8** | **204.2** | **38.7** | **242.9** |
| Other Tariff and Contract Based Revenues | 25.4 | 9.1 | 34.5 | 14.3 | 8.6 | 22.9 |
| **Total Revenue from Contracts with Customers** | **236.7** | **64.6** | **301.3** | **218.5** | **47.3** | **265.8** |
| Regulatory amortization and other | 4.7 | (7.8) | (3.1) | (0.6) | 4.1 | 3.5 |
| **Total Revenues** | **$ 241.4** | **$ 56.8** | **$ 298.2** | **$ 217.9** | **$ 51.4** | **$ 269.3** |

| | Six Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | June 30, 2021 | | | June 30, 2020 | | |
| | Electric | Natural Gas | Total | Electric | Natural Gas | Total |
| Montana | $ 165.9 | $ 72.5 | $ 238.4 | $ 159.2 | $ 55.8 | $ 215.0 |
| South Dakota | 32.2 | 16.5 | 48.7 | 33.5 | 15.0 | 48.5 |
| Nebraska | — | 12.1 | 12.1 | — | 11.2 | 11.2 |
| **Residential** | **198.1** | **101.1** | **299.2** | **192.7** | **82.0** | **274.7** |
| Montana | 171.4 | 36.8 | 208.2 | 163.4 | 27.4 | 190.8 |
| South Dakota | 48.2 | 10.8 | 59.0 | 49.7 | 10.2 | 59.9 |
| Nebraska | — | 6.2 | 6.2 | — | 5.5 | 5.5 |
| **Commercial** | **219.6** | **53.8** | **273.4** | **213.1** | **43.1** | **256.2** |
| Industrial | 18.9 | 0.7 | 19.6 | 18.0 | 0.4 | 18.4 |
| Lighting, Governmental, Irrigation, and Interdepartmental | 13.7 | 0.9 | 14.6 | 14.5 | 0.6 | 15.1 |
| **Total Customer Revenues** | **450.3** | **156.5** | **606.8** | **438.3** | **126.1** | **564.4** |
| Other Tariff and Contract Based Revenues | 42.3 | 18.8 | 61.1 | 29.2 | 18.3 | 47.5 |
| **Total Revenue from Contracts with Customers** | **492.6** | **175.3** | **667.9** | **467.5** | **144.4** | **611.9** |
| Regulatory amortization and other | 18.9 | 12.2 | 31.1 | (5.0) | (2.3) | (7.3) |
| **Total Revenues** | **$ 511.5** | **$ 187.5** | **$ 699.0** | **$ 462.5** | **$ 142.1** | **$ 604.6** |

## (8) Earnings Per Share

Basic earnings per share are computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution of common stock equivalent shares that could occur if unvested shares were to vest. Common stock equivalent shares are calculated using the treasury stock method, as applicable. The dilutive effect is computed by dividing earnings applicable to common stock by the weighted average number of common shares outstanding plus the effect of the outstanding unvested restricted stock and performance share awards. Average shares used in computing the basic and diluted earnings per share are as follows:

| | Three Months Ended | |
|---|---|---|
| | June 30, 2021 | June 30, 2020 |
| Basic computation | 50,989,182 | 50,569,725 |
| *Dilutive effect of:* | | |
| Performance share awards[(1)] | 132,138 | 69,280 |
| Diluted computation | 51,121,320 | 50,639,005 |

| | Six Months Ended | |
|---|---|---|
| | June 30, 2021 | June 30, 2020 |
| Basic computation | 50,811,303 | 50,538,260 |
| *Dilutive effect of:* | | |
| Performance share awards[(1)] | 131,507 | 75,159 |
| Diluted computation | 50,942,810 | 50,613,419 |

(1) Performance share awards are included in diluted weighted average number of shares outstanding based upon what would be issued if the end of the most recent reporting period was the end of the term of the award.

As of June 30, 2021, there were 23,924 shares from performance and restricted share awards which were antidilutive and excluded from the earnings per share calculations.

### (9) Employee Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. Net periodic benefit cost (credit) for our pension and other postretirement plans consists of the following (in thousands):

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2021 | 2020 | 2021 | 2020 |
| Components of Net Periodic Benefit Cost (Credit) | | | | |
| Service cost | $ 3,286 | $ 2,712 | $ 104 | $ 93 |
| Interest cost | 4,814 | 5,694 | 84 | 137 |
| Expected return on plan assets | (6,841) | (6,536) | (229) | (245) |
| Amortization of prior service credit | — | — | (459) | (470) |
| Recognized actuarial loss (gain) | 2,261 | 1,234 | (4) | (12) |
| Net periodic benefit cost (credit) | $ 3,520 | $ 3,104 | $ (504) | $ (497) |

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2021 | 2020 | 2021 | 2020 |
| Components of Net Periodic Benefit Cost (Credit) | | | | |
| Service cost | $ 6,549 | $ 5,558 | $ 203 | $ 185 |
| Interest cost | 9,410 | 11,420 | 159 | 246 |
| Expected return on plan assets | (13,684) | (13,081) | (459) | (492) |
| Amortization of prior service cost (credit) | — | — | (918) | (941) |
| Recognized actuarial loss (gain) | 3,489 | 2,514 | (15) | (30) |
| Net periodic benefit cost (credit) | $ 5,764 | $ 6,411 | $ (1,030) | $ (1,032) |

We contributed $4.5 million to our pension plans during the six months ended June 30, 2021. We expect to contribute an additional $6.7 million to our pension plans during the remainder of 2021.

### (10) Commitments and Contingencies

**ENVIRONMENTAL LIABILITIES AND REGULATION**

#### Environmental Matters

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us, is estimated to range between $25.5 million to $31.1 million. As of June 30, 2021, we had a reserve of approximately $27.8 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our consolidated financial position or results of operations.

***Manufactured Gas Plants -*** Approximately \$21.6 million of our environmental reserve accrual is related to the following manufactured gas plants.

South Dakota - A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of June 30, 2021, the reserve for remediation costs at this site was approximately \$8.0 million, and we estimate that approximately \$2.9 million of this amount will be incurred during the next five years.

Nebraska - We own sites in North Platte, Kearney, and Grand Island, Nebraska on which former manufactured gas facilities were located. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

Montana - We own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana’s state superfund list, were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site.

In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments. The MDEQ approved the RIWP in March 2020 and we expect work at the Helena site to continue through 2021.

MDEQ has indicated it expects to proceed in listing the Missoula site as a Montana superfund site. After researching historical ownership we have identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. The other party is assuming the lead role at the site and has expressed its intent to pursue a voluntary remediation at the Missoula site. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

***Global Climate Change -*** National and international actions have been initiated to address global climate change and the contribution of greenhouse gas (GHG) including, most significantly, carbon dioxide ($CO_2$). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, actions at the state level, investor activism and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four coal-fired electric generating plants, all of which are operated by other companies. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, Congress has not passed any federal climate change legislation regarding GHG emissions from coal fired plants, and we cannot predict the timing or form of any potential legislation. In 2019, the EPA finalized the Affordable Clean Energy Rule (ACE), which repealed the 2015 Clean Power Plan (CPP) in regulating GHG emissions from coal-fired plants. The U.S. Court of Appeals for the District of Columbia Circuit issued an opinion on January 19, 2021, vacating the ACE and remanding it to EPA for further action. It is widely expected that the Biden Administration will develop an alternative plan for reducing GHG emissions from coal-fired plants, and in a memorandum dated February 12, 2021, EPA stated its belief that the January 19, 2021 opinion left neither the ACE nor the CPP rules in place.

We cannot predict whether or how GHG emission regulations will be applied to our plants, including any actions taken by the relevant state authorities. In addition, it is unclear how pending or future litigation relating to GHG matters will impact us. As GHG regulations are implemented, it could result in additional compliance costs impacting our future results of operations and financial position if such costs are not recovered through regulated rates. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impact customers in our region.

Future additional environmental requirements could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Technology to efficiently capture, remove and/or sequester such GHG emissions may not be available within a timeframe consistent with the implementation of any such requirements. Physical impacts of climate change also may present potential risks for severe weather, such as droughts, fires, floods, ice storms and tornadoes, in the locations where we operate or have interests. These potential risks may impact costs for electric and natural gas supply and maintenance of generation, distribution, and transmission facilities.

***Clean Air Act Rules and Associated Emission Control Equipment Expenditures -*** The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act (CAA) that could require the installation of emission control equipment at the generation plants in which we have joint ownership. Air emissions at our thermal generating plants are managed by the use of emissions and combustion controls and monitoring, and sulfur dioxide allowances. These measures are anticipated to be sufficient to permit the facilities to continue to meet current air emissions compliance requirements.

***Regional Haze Rules -*** In January 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021.

By July 31, 2021, Montana must develop and submit to the EPA for approval a revised plan that demonstrates reasonable progress toward eliminating man-made emissions of visibility impairing pollutants, which could impact Colstrip Unit 4. In March 2017, we filed a Petition for Review of these amendments with the D.C. Circuit, which was consolidated with other petitions challenging the final rule. The D.C. Circuit has granted the EPA’s request to hold the case in abeyance while the EPA considers further administrative action to revisit the rule.

The North Dakota Department of Environmental Quality (ND DEQ) is expected to decide on statewide reduction strategy in 2021 which could impact the Coyote generating facility. Once the ND DEQ establishes a State Implementation Plan (SIP) for regional haze compliance, the SIP will be submitted for approval to the North Dakota Governor’s office and finally to EPA for approval. Following EPA’s approval, which is not expected to occur until the second half of 2021 or later, the joint owners of the Coyote generating facility will assess the requirements, if any, and determine whether to move forward with the installation of additional emissions controls. Additional controls, if any, to meet new emission restrictions would have to be in place by the end of 2028 under the current schedule.

***Jointly Owned Plants -*** We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been or may be issued or proposed.

***Other -*** We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

## LEGAL PROCEEDINGS

### Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is a solar QF developer seeking to construct small solar facilities in Montana. We began negotiating with PNWS in early 2016 to purchase the output from 21 of its proposed facilities pursuant to our standard QF-1 Tariff, which is applicable to projects no larger than 3 MWs.

On June 16, 2016, however, the MPSC suspended the availability of the QF-1 Tariff standard rates for that category of solar projects, which included the projects proposed by PNWS. The MPSC exempted from the suspension any projects for which a QF had both submitted a signed power purchase agreement and had executed an interconnection agreement with us by June 16, 2016. Although we had signed four power purchase agreements with PNWS as of that date, we had not entered into interconnection agreements with PNWS for any of those projects. As a result, none of the PNWS projects in Montana qualified for the exemption.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and a judicial declaration that some or all of the 21 proposed power purchase agreements it had proposed to us were in effect despite the MPSC's Order. We removed the state lawsuit to the United States District Court for the District of Montana (Court).

PNWS also requested the MPSC to exempt its projects from the tariff suspension and allow those projects to receive the QF-1 tariff rate that had been in effect prior to the suspension. We joined in PNWS's request for relief with respect to four of the projects, but the MPSC did not grant any of the relief requested by PNWS or us.

In August 2017, pursuant to a non-monetary, partial settlement with us, PNWS amended its original complaint to limit its claims for enforcement and/or damages to only four of the 21 power purchase agreements. As a result, the amount of damages sought by the plaintiff was reduced to approximately $8.0 million for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019 and subsequent settlement efforts also have been unsuccessful. A jury trial was scheduled to begin on June 2, 2020, but the trial was postponed because of the court closure due to the COVID-19 pandemic and has not yet been rescheduled.

The parties recently agreed that the remaining liability issues can be decided by the court as a matter of law. The parties have submitted briefs addressing key liability issues in the case and expect the court to grant full or partial summary judgement in favor of either party, and then schedule a trial date for any remaining issues.

We dispute the remaining claims in PNWS' lawsuit and will continue to vigorously defend against them. We cannot currently predict an outcome in this litigation. If the plaintiff prevails and obtains damages for a breach of contract, we may seek to recover those damages in rates from customers. We cannot predict the outcome of any such effort.

### State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our, and formerly Talen's, hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

The litigation has a long prior history. In 2012, the United States Supreme Court issued a decision holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach "at least from the head of the first waterfall to the foot of the last" was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State's Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). The State filed a motion to remand. Following briefing and argument, on October 10, 2017, the Federal District Court entered an order denying the State's motion.

Because the State's Complaint included a claim that the State owned the riverbeds in the Great Falls Reach, on October 16, 2017, we and Talen renewed our earlier-filed motions seeking to dismiss the portion of the State's Complaint concerning the Great Falls Reach in light of the United States Supreme Court's decision. On August 1, 2018, the Federal District Court granted the motions to dismiss the State's Complaint as it pertains to approximately 8.2 miles of riverbed from "the head of the Black Eagle Falls to the foot of the Great Falls." In particular, the dismissal pertained to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. While the dismissal of these four facilities may be subject to appeal, that appeal would not likely occur until after judgment in the case. On February 12, 2019, the Federal District Court granted our motion to join the United States as a defendant to the litigation. As a result, on October 31, 2019, the State filed and served an Amended Complaint including the United States as a defendant and removing claims of ownership for the hydroelectric facilities on the Great Falls Reach, except for the Morony and the Black Eagle Developments. We and Talen filed answers to the Amended Complaint on December 13, 2019, and the United States answered on February 5, 2020. On May 12, 2021, the Federal District Court reset the trial date on the issue of navigability to January 3, 2022. Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable.

We dispute the State's claims and intend to vigorously defend the lawsuit. At this time, we cannot predict an outcome. If the Federal District Court determines the riverbeds are navigable under the remaining six facilities that were not dismissed and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $3.8 million commencing when we acquired the facilities in November 2014. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

**Colstrip Arbitration and Litigation**

As part of the settlement of litigation brought by the Sierra Club and the Montana Environmental Information Center against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding those units, including their shut down, were made by their respective owners. The six owners of Units 3 and 4 currently share the operating costs pursuant to the terms of an operating agreement among them, the Ownership and Operation Agreement (O&O Agreement). Costs of common facilities were historically shared among the owners of all four units. With the closure of Units 1 and 2, we have incurred additional operating costs with respect to our interest in Unit 4 and expect to experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines. We expect to incorporate any reduction in revenue in our next general electric rate filing, resulting in lower revenue credits to certain customers.

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Recovery of costs associated with the closure of the facility is subject to MPSC approval. Three of the joint owners of Units 3 and 4 are subject to regulation in Washington and in May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to "eliminate coal-fired resources from [their] allocation of electricity" on or before December 31, 2025, after which date they may no longer include their share of coal-fired resources in their regulated electric supply portfolio. As a result of the Washington legislation, four of the six joint owners of Units 3 and 4 requested the operator prepare a 2021 budget reflecting closure of Units 3 and 4 by 2025, and alternately a closure of Unit 3 by 2025 and a closure of Unit 4 by 2027. Differing viewpoints on closure dates delayed approval of the 2021 budget, until it was approved on March 22, 2021. We anticipate the annual budgeting process for Units 3 and 4 may raise similar efforts to tie budgeting to a closure date, resulting in future budgets that may not be sufficient to maintain the reliability of Units 3 and 4.

While we believe closure requires each owner's consent, there are differences among the owners as to this issue under the O&O Agreement. On March 12, 2021, we initiated an arbitration under the O&O Agreement (the "Arbitration"), which seeks to resolve the primary issue of whether closure of Units 3 and 4 can be accomplished without each joint owner's consent and to clarify the obligations of the joint owners to continue to fund operations until all joint owners agree on closure.

The Arbitration has given rise to three lawsuits concerning the number of arbitrators, the venue and the applicable arbitration laws. The four joint owners from the Pacific Northwest assert the Arbitration must be conducted under the O&O Agreement, with one arbitrator, in Spokane County, Washington, and pursuant to the Washington Arbitration Act. The fifth joint owner asserts the Arbitration must be conducted per the terms of Montana Senate Bill 265 (SB 265), which requires the Arbitration be conducted, with three arbitrators, in Montana and pursuant to the Montana Uniform Arbitration Act. The three initiated lawsuits do not make direct financial demands, and instead, are intended to address issues related to process for the Arbitration.

Since the Arbitration was initiated, and despite the litigation, we have worked and continue to work with the other joint owners to arrive at an agreed upon process for the Arbitration.

## Other Legal Proceedings

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

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

### *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. We define Gross Margin as Operating Revenues less Cost of Sales as presented in our Condensed Consolidated Statements of Income. This measure differs from the GAAP definition of Gross Margin due to the exclusion of Depreciation and depletion expenses, which are presented separate from Cost of Sales in our Condensed Consolidated Statements of Income. The following discussion includes a reconciliation of Gross Margin to Operating Revenues, the most directly comparable GAAP measure.

Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze our financial performance in that it excludes the effect on total revenues caused by volatility in energy costs and associated regulatory mechanisms. This information is intended to enhance an investor's overall understanding of results. Under our various state regulatory mechanisms, as detailed below, our supply costs are generally collected from customers. In addition, Gross Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow for recovery of operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates and other factors impact our results of operations. Our Gross Margin measure may not be comparable to that of other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

## OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and/or natural gas to approximately 743,000 customers in Montana, South Dakota, Nebraska and Yellowstone National Park. For a discussion of NorthWestern's business strategy, see Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2020.

We are working to deliver safe, reliable and innovative energy solutions that create value for customers, communities, employees and investors. This includes bridging our history as a regulated utility safely providing low-cost and reliable service with our future as a globally-aware company offering a broader array of services performed by highly-adaptable and skilled employees. We seek to deliver value to our customers by providing high reliability and customer service, and an environmentally sustainable generation mix at an affordable price. We are focused on delivering long-term shareholder value through:

- Infrastructure investment focused on a stronger and smarter grid to improve the customer experience, while enhancing grid reliability and safety. This includes automation in distribution and substations that enables the use of changing technology.

- Integrating supply resources that balance reliability, cost, capacity, and sustainability considerations with more predictable long-term commodity prices.

- Continually improving our operating efficiency. Financial discipline is essential to earning our authorized return on invested capital and maintaining a strong balance sheet, stable cash flows, and quality credit ratings.

We expect to pursue these investment opportunities and manage our business in a manner that allows us to be flexible in adjusting to changing economic conditions by adjusting the timing and scale of the projects.

As you read this discussion and analysis, refer to our Condensed Consolidated Statements of Income, which present the results of our operations for the three and six months ended June 30, 2021 and 2020.

## HOW WE PERFORMED AGAINST OUR SECOND QUARTER 2020 RESULTS

| | Three Months Ended June 30, 2021 vs. 2020 | | |
|---|---|---|---|
| | Income Before Income Taxes | Income Tax (Expense) Benefit | Net Income |
| | (in millions) | | |
| **Second Quarter 2020** | **$ 20.8** | **$ 0.7** | **$ 21.5** |
| *Items increasing (decreasing) net income:* | | | |
| Higher Montana electric transmission revenue | 9.1 | (2.3) | 6.8 |
| Electric QF liability adjustment | 6.1 | (1.5) | 4.6 |
| Higher electric retail volumes | 5.6 | (1.4) | 4.2 |
| Higher operating, general, and administrative expenses impacting net income | (3.2) | 0.7 | (2.5) |
| Higher depreciation and depletion | (2.0) | 0.5 | (1.5) |
| Lower Montana electric supply cost recovery | (0.8) | 0.2 | (0.6) |
| Lower Montana natural gas volumes | (0.5) | 0.2 | (0.3) |
| Other | 3.5 | 1.5 | 5.0 |
| **Second Quarter 2021** | **$ 38.6** | **$ (1.4)** | **$ 37.2** |
| **Change in Net Income** | | | **$ 15.7** |

Consolidated net income for the three months ended June 30, 2021 was $37.2 million as compared with $21.5 million for the same period in 2020. This increase was primarily due to improved gross margin driven by higher Montana transmission loads and rates, a favorable electric QF liability adjustment as compared with the prior period, and warmer spring weather, partly offset by higher operating costs and income tax expense.

## SIGNIFICANT TRENDS AND REGULATION

### Electric Resource Planning - Montana

We are currently 630 MW short of our peak needs and we cover the shortfall through market purchases. Absent resource additions, we forecast that our portfolio will be 725 MW short by 2025, considering expiring contracts and a modest increase in customer demand. We issued an all-source competitive solicitation request in January 2020 for up to 280 MWs of peaking and flexible capacity to be available for commercial operation in late 2023 or early 2024 (the January 2020 request for proposal (RFP)). Further, we expect to issue additional all-source competitive solicitation requests during 2022.

Initial bids for the January 2020 RFP were received in July 2020. A third-party RFP Administrator evaluated the bids with the following portfolio of projects selected:

- Laurel Generating Station - the construction of a 175 MW natural gas-fired generation plant near Laurel, Montana, at a cost of approximately $250 million, which we will own;
- Beartooth Battery - A 20-year agreement to purchase capacity and ancillary services produced from a 50 MW battery energy storage facility that will be constructed in Yellowstone County, Montana; and
- Powerex Transaction - a 5-year power purchase agreement for 100 MWs of capacity and energy products originating predominately from hydroelectric resources.

On May 19, 2021, we filed an application with the MPSC for approval to acquire the Laurel Generating Station and Beartooth Battery agreement as new capacity resources. These resources, together with the Powerex Transaction, will help address our identified capacity shortage. The Powerex Transaction, is not part of this application with the MPSC. On July 26, 2021, the MPSC concluded that the application met the minimum filing requirements and is adequate. This triggers the requirement that the MPSC issue an order within 270 days of receipt of an adequate application. The MPSC can grant itself an additional 90 days if it determines that extraordinary circumstances require it. Assuming approval of the Laurel Generating Station project, the costs would be incremental to our current capital and financing projections.

## Regulatory Update

We do not expect to make general rate case filings in any of our regulatory jurisdictions during 2021. We have recently filed several other regulatory filings, primarily in our Montana jurisdiction, including:

- An April 15, 2021 filing of a motion requesting to delay the implementation of our fixed cost recovery mechanism pilot in our Montana jurisdiction for another year until July 2022 or beyond, due to the continued uncertainties created by the COVID-19 pandemic. On June 29, 2021, the MPSC granted our motion and a written order is pending; and
- An April 21, 2021 filing requesting approval to increase the forecasted costs used to develop rates for the recovery of electric power costs through our Power Costs and Credits Adjustment Mechanism (PCCAM) by approximately $17 million, or potentially a greater increase to reflect current market prices and new capacity contracts. On June 29, 2021, the MPSC approved implementing our request for interim rates reflecting the $17 million increase, subject to refund.

## February Cold Weather Event

The February 2021 prolonged cold spell resulted in record winter peak demand for electricity and natural gas. The broad reach of this event across the United States and other market factors resulted in an extreme price excursion for purchased power and natural gas. In our South Dakota and Nebraska service territories, natural gas costs for the month of February 2021 exceeded the total cost for all of 2020. Fuel and purchased power costs in these jurisdictions are recovered through fuel adjustment clauses. We've incorporated the liquidity impacts into our overall 2021 financing plans.

The Nebraska Public Service Commission (NPSC) opened a docket on March 2, 2021 to investigate the effect of this cold weather event on natural gas supply. In this docket, we proposed recovery of our costs for February 13, 2021 to February 18, 2021 over a two-year period, which was subsequently approved by the NPSC on May 11, 2021, and a regulatory asset of approximately $26 million was recorded for these costs, with a remaining balance of $26.0 million as of June 30, 2021.

The South Dakota Public Utilities Commission issued an order allowing recovery of natural gas costs for the same time period over a one-year period, effective March 2, 2021. A regulatory asset of approximately $22.0 million was recorded for these costs, with a remaining balance of $17.5 million as of June 30, 2021.

## COVID-19 Pandemic

The COVID-19 pandemic has had widespread impacts on people, economies, businesses and financial markets. Beginning in March 2020, the pandemic and resulting economic conditions began impacting our business operations and financial results. Our 2020 financial results were impacted by lower sales volumes, an increase in reserves for uncollectible accounts and an increase in interest expense, partly offset by lower operating, general and administrative expenses. We have experienced improving conditions in our service territories during 2021, which has positively impacted our business as compared to 2020. The ultimate impact of the pandemic on our financial results for 2021 and beyond depends on the evolving landscape of the pandemic and the public health responses to contain it, as well as the substance and pace of the macroeconomic recovery. If health conditions deteriorate or the economic recovery stalls, it could have the result of lower demand for electricity and natural gas, as well as reduced ability of various customers, contractors, suppliers and other business partners to fulfill their obligations. These impacts could have a material adverse effect on our results of operations, financial condition and prospects.

## Financing Activity

We anticipate financing our ongoing maintenance and capital programs with a combination of cash flows from operations, first mortgage bonds and equity issuances.

In March 2021, we issued and sold $100.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 1.00% maturing on March 26, 2024. The net proceeds were used to repay in full our outstanding $100.0 million one-year term loan that was due April 2, 2021.

In April 2021, we entered into an Equity Distribution Agreement pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an ATM program, including an equity forward sales component. During the three months ended June 30, 2021, we issued 879,309 shares of our common stock at an average price of $64.91, for net proceeds of $56.3 million. We expect to issue the remainder of the $200.0 million in 2021 to support our current capital program and maintain and protect our credit ratings. Capital investment in response to our Montana electric supply resource planning would be incremental to these amounts. Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

## RESULTS OF OPERATIONS

Our consolidated results include the results of our divisions and subsidiaries constituting each of our business segments. The overall consolidated discussion is followed by a detailed discussion of gross margin by segment.

### *Factors Affecting Results of Operations*

Our revenues may fluctuate substantially with changes in supply costs, which are generally collected in rates from customers. In addition, various regulatory agencies approve the prices for electric and natural gas utility service within their respective jurisdictions and regulate our ability to recover costs from customers.

Revenues are also impacted by customer growth and usage, the latter of which is primarily affected by weather. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among our residential and commercial customers. We measure this effect using degree-days, which is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Heating degree-days result when the average daily temperature is less than the baseline. Cooling degree-days result when the average daily temperature is greater than the baseline. The statistical weather information in our regulated segments represents a comparison of this data.

### *OVERALL CONSOLIDATED RESULTS*

### Three Months Ended June 30, 2021 Compared with the Three Months Ended June 30, 2020

Consolidated net income for the three months ended June 30, 2021 was $37.2 million as compared with $21.5 million for the same period in 2020. This increase was primarily due to improved gross margin driven by higher Montana transmission loads and rates, a favorable electric QF liability adjustment as compared with the prior period, and warmer spring weather, partly offset by higher operating costs and income tax expense.

Consolidated operating revenues for the three months ended June 30, 2021 were $298.2 million as compared with $269.3 million for the same period in 2020. Consolidated gross margin for the three months ended June 30, 2021 was $230.3 million as compared with $208.3 million for the same period in 2020, an increase of $22.0 million.

| | Electric | | Natural Gas | | Total | |
|---|---|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 | 2021 | 2020 |
| | (dollars in millions) | | | | | |
| **Reconciliation of operating revenue to gross margin:** | | | | | | |
| Operating Revenues | $ 241.4 | $ 217.9 | $ 56.8 | $ 51.4 | $ 298.2 | $ 269.3 |
| Cost of Sales | 49.2 | 48.3 | 18.7 | 12.7 | 67.9 | 61.0 |
| **Gross Margin(1)** | **$ 192.2** | **$ 169.6** | **$ 38.1** | **$ 38.7** | **$ 230.3** | **$ 208.3** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | % Change |
| | (dollars in millions) | | | |
| **Gross Margin** | | | | |
| Electric | $ 192.2 | $ 169.6 | $ 22.6 | 13.3 % |
| Natural Gas | 38.1 | 38.7 | (0.6) | (1.6) |
| **Total Gross Margin(1)** | **$ 230.3** | **$ 208.3** | **$ 22.0** | **10.6 %** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Primary components of the change in gross margin include the following (in millions):

| | Gross Margin 2021 vs. 2020 | |
|---|---|---|
| **Gross Margin Items Impacting Net Income** | | |
| Electric transmission | $ | 9.1 |
| Electric QF liability adjustment | | 6.1 |
| Electric retail volumes | | 5.6 |
| Montana electric supply cost recovery | | (0.8) |
| Natural gas retail volumes | | (0.5) |
| Montana natural gas production rates | | (0.2) |
| Other | | 0.9 |
| **Change in Gross Margin Impacting Net Income** | | **20.2** |
| **Gross Margin Items Offset Within Net Income** | | |
| Operating expenses recovered in revenue, offset in operating expense | | 0.8 |
| Production tax credits reducing revenue, offset in income tax benefit | | 0.5 |
| Property taxes recovered in revenue, offset in property tax expense | | 0.3 |
| Gas production taxes recovered in revenue, offset in property and other taxes | | 0.2 |
| **Change in Gross Margin Items Offset Within Net Income** | | **1.8** |
| **Increase in Consolidated Gross Margin[(1)]** | **$** | **22.0** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Consolidated gross margin increased $22.0 million, including a $20.2 million increase from items impacting net income and a $1.8 million increase from items offset within net income.

The change in consolidated gross margin for items impacting net income includes the following:

- Higher Montana transmission rates, the recognition of approximately $4.7 million of deferred interim revenues, and higher demand to transmit energy across our transmission lines due to market conditions and pricing;
- A favorable adjustment of our electric QF liability (unrecoverable costs associated with the Public Utility Regulatory Policies Act of 1978 (PURPA) contracts as part of a 2002 stipulation with the MPSC and other parties) reflecting a $9.2 million gain in 2021, as compared with a $3.1 million gain for the same period in 2020, due to the combination of:
    - A $2.6 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $0.9 million favorable reduction in costs in the prior period;
    - A negative adjustment, increasing the QF liability by $2.1 million, reflecting annual actual contract price escalation, which was more than previously estimated, compared to a favorable adjustment of $2.2 million in the prior year due to lower actual price escalation; and
    - A favorable adjustment of approximately $8.7 million decreasing the QF liability due to a one-time clarification in contract term.
- An increase in electric retail revenue due to warmer spring weather, overall customer growth, and increased commercial volume as compared to the prior year. Residential retail volumes remained flat with warmer spring weather offset by lower usage than in the prior period;
- Higher Montana electric supply costs as compared with the prior period;
- A decrease in gas volumes due to warmer weather, partly offset by customer growth; and
- A reduction of rates from the step down of our Montana gas production assets.

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | % Change |
| | (dollars in millions) | | | |
| **Operating Expenses (excluding cost of sales)** | | | | |
| Operating, general and administrative | $ 77.1 | $ 71.7 | $ 5.4 | 7.5 % |
| Property and other taxes | 47.3 | 47.0 | 0.3 | 0.6 |
| Depreciation and depletion | 46.8 | 44.8 | 2.0 | 4.5 |
| | **$ 171.2** | **$ 163.5** | **$ 7.7** | **4.7 %** |

Consolidated operating, general and administrative expenses were $77.1 million for the three months ended June 30, 2021, as compared with $71.7 million for the three months ended June 30, 2020. Primary components of the change include the following (in millions):

| | Operating, General & Administrative Expenses 2021 vs. 2020 |
|---|---|
| **Operating, General & Administrative Expenses Impacting Net Income** | |
| Generation maintenance | $ 2.0 |
| Employee benefits | 1.0 |
| Technology implementation and maintenance | 0.9 |
| Labor | 0.3 |
| Travel and training | 0.2 |
| Uncollectible accounts | (2.8) |
| Other | 1.6 |
| **Change in Items Impacting Net Income** | **3.2** |
| | |
| **Operating, General & Administrative Expenses Offset Within Net Income** | |
| Non-employee directors deferred compensation, offset in other income | 0.8 |
| Operating expenses recovered in trackers, offset in revenue | 0.8 |
| Pension and other postretirement benefits, offset in other income | 0.6 |
| **Change in Operating, General & Administrative Expense Items Offset Within Net Income** | **2.2** |
| **Increase in Operating, General & Administrative Expenses** | **$ 5.4** |

Consolidated operating, general and administrative expenses increased $5.4 million, including a $3.2 million increase from items impacting net income and a $2.2 million increase from items offset within net income.

The change in consolidated operating, general and administrative expenses for items impacting net income includes the following:

- Higher maintenance costs at our electric generation facilities;
- Higher employee benefit costs primarily due to an increase in medical benefits;
- Higher technology implementation and maintenance costs;
- Higher labor costs due primarily to compensation increases, partly offset by more time being spent by employees on capital projects than maintenance projects (which are expensed);
- Higher travel and training costs; and
- Decreased uncollectible accounts due to collections of previously written off amounts in the current period. In the second quarter of 2020, we voluntarily suspended service disconnections for non-payment, to help customers who may be financially impacted by the COVID-19 pandemic.

Property and other taxes were $47.3 million for the three months ended June 30, 2021, as compared with $47.0 million in the same period of 2020. This increase was due primarily to an increase in Montana state and local taxes. We estimate property taxes throughout each year, and update those estimates based on valuation reports received from the Montana Department of

Revenue. Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and adjust our rates to recover the increase between rate cases less the amount allocated to FERC-jurisdictional customers and net of the associated income tax benefit.

Depreciation and depletion expense was $46.8 million for the three months ended June 30, 2021, as compared with $44.8 million in the same period of 2020. This increase was primarily due to plant additions.

Consolidated operating income for the three months ended June 30, 2021 was $59.0 million as compared with $44.8 million in the same period of 2020. This increase was primarily due to improved gross margin driven by higher Montana transmission loads and rates, a favorable electric QF liability adjustment as compared with the prior period, and warmer spring weather, offset in part by higher operating expenses.

Consolidated interest expense was $23.5 million for the three months ended June 30, 2021 as compared with $24.3 million for the same period of 2020. This decrease was primarily due to higher capitalization of Allowance for Funds Used During Construction (AFUDC), partly offset by higher borrowings.

Consolidated other income was $3.0 million for the three months ended June 30, 2021 as compared to $0.2 million during the same period of 2020. This increase includes approximately $1.4 million related to items offset in operating, general and administrative expense with no impact to net income, and higher capitalization of AFUDC. Items offset in operating, general and administrative expense includes approximately $0.8 million increase in the value of deferred shares held in trust for non-employee directors deferred compensation and a decrease in other pension expense of $0.6 million.

Consolidated income tax expense for the three months ended June 30, 2021 was $1.4 million as compared to an income tax benefit of $0.7 million in the same period of 2020. Our effective tax rate for the three months ended June 30, 2021 was 3.4% as compared with (3.5)% for the same period in 2020. We expect our effective tax rate to range between (2.5)% to 2.5% in 2021.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (in millions):

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2021 | | 2020 | |
| Income Before Income Taxes | $ 38.6 | | $ 20.8 | |
| | | | | |
| Income tax calculated at federal statutory rate | 8.1 | 21.0 % | 4.4 | 21.0 % |
| | | | | |
| Permanent or flow-through adjustments: | | | | |
| State income tax, net of federal provisions | 0.2 | 0.6 | 0.0 | 0.0 |
| Flow-through repairs deductions | (4.2) | (11.0) | (3.2) | (15.4) |
| Production tax credits | (2.3) | (5.9) | (1.8) | (8.5) |
| Plant and depreciation of flow-through items | (0.2) | (0.5) | 0.1 | 0.3 |
| Amortization of excess deferred income tax | (0.1) | (0.4) | (0.2) | (0.7) |
| Other, net | (0.1) | (0.4) | 0.0 | (0.2) |
| | (6.7) | (17.6) | (5.1) | (24.5) |
| | | | | |
| **Income tax expense (benefit)** | $ 1.4 | 3.4 % | $ (0.7) | (3.5)% |

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

### Six Months Ended June 30, 2021 Compared with the Six Months Ended June 30, 2020

Consolidated net income for the six months ended June 30, 2021 was $100.3 million as compared with $72.2 million for the same period in 2020. This increase was primarily due to improved gross margin driven by higher Montana transmission loads and rates, a favorable electric QF liability adjustment as compared with the prior period, favorable weather, and higher commercial demand as compared to the prior year due to the COVID-19 pandemic related shutdowns, partly offset by higher Montana electric supply costs, depreciation expense, and income tax expense.

Consolidated operating revenues for the six months ended June 30, 2021 were $699.0 million as compared with $604.6 million for the same period in 2020. Consolidated gross margin for the six months ended June 30, 2021 was $486.5 million as compared with $452.3 million for the same period in 2020, an increase of $34.2 million.

| | Electric | | Natural Gas | | Total | |
|---|---|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 | 2021 | 2020 |
| | | | (dollars in millions) | | | |
| **Reconciliation of operating revenue to gross margin:** | | | | | | |
| Operating Revenues | $ 511.5 | $ 462.5 | $ 187.5 | $ 142.1 | $ 699.0 | $ 604.6 |
| Cost of Sales | 129.4 | 112.1 | 83.1 | 40.2 | 212.5 | 152.3 |
| **Gross Margin(1)** | **$ 382.1** | **$ 350.4** | **$ 104.4** | **$ 101.9** | **$ 486.5** | **$ 452.3** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2021 | 2020 | Change | % Change |
| | (dollars in millions) | | | |
| **Gross Margin** | | | | |
| Electric | $ 382.1 | $ 350.4 | $ 31.7 | 9.0 % |
| Natural Gas | 104.4 | 101.9 | 2.5 | 2.5 |
| **Total Gross Margin(1)** | **$ 486.5** | **$ 452.3** | **$ 34.2** | **7.6 %** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Primary components of the change in gross margin include the following (in millions):

| | Gross Margin 2021 vs. 2020 |
|---|---|
| **Gross Margin Items Impacting Net Income** | |
| Electric transmission | $ 11.2 |
| Electric retail volumes | 9.7 |
| Electric QF liability adjustment | 6.1 |
| Natural gas retail volumes | 2.3 |
| Montana electric supply cost recovery | (2.2) |
| Montana natural gas production rates | (0.7) |
| Other | 3.7 |
| **Change in Gross Margin Impacting Net Income** | **30.1** |
| **Gross Margin Items Offset Within Net Income** | |
| Property taxes recovered in revenue, offset in property tax expense | 2.3 |
| Production tax credits reducing revenue, offset in income tax benefit | 1.6 |
| Gas production taxes recovered in revenue, offset in property and other taxes | 0.2 |
| **Change in Gross Margin Items Offset Within Net Income** | **4.1** |
| **Increase in Consolidated Gross Margin(1)** | **$ 34.2** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Consolidated gross margin increased $34.2 million, including a $30.1 million increase from items impacting net income and a $4.1 million increase from items offset within net income.

The change in consolidated gross margin for items impacting net income includes the following:

- Higher Montana transmission rates, the recognition of approximately $4.7 million of deferred interim revenues, and higher demand to transmit energy across our transmission lines due to market conditions and pricing;
- An increase in electric retail revenue driven by colder winter weather in Montana, warmer spring weather in both Montana and South Dakota jurisdictions, customer growth, and increased commercial volume in the current period as compared to the COVID-19 pandemic related shutdowns in the prior year, partly offset by warmer winter weather in South Dakota;
- A more favorable adjustment of our electric QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) reflecting a $9.2 million gain in 2021, as compared with a $3.1 million gain for the same period in 2020, due to the combination of:
    - A $2.6 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $0.9 million favorable reduction in costs in the prior period;
    - A negative adjustment, increasing the QF liability by $2.1 million, reflecting annual actual contract price escalation, which was more than previously estimated, compared to a favorable adjustment of $2.2 million in the prior year due to lower actual price escalation; and
    - A favorable adjustment of approximately $8.7 million decreasing the QF liability due to a one-time clarification in contract term.
- An increase in gas retail volumes due to colder winter weather in our Montana and Nebraska jurisdictions and customer growth, partly offset by warmer winter weather in our South Dakota jurisdiction and warmer spring weather in all jurisdictions;
- Higher Montana electric supply costs as compared with the prior period; and
- A reduction of rates from the step down of our Montana gas production assets.

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | **2021** | **2020** | **Change** | **% Change** |
| | (dollars in millions) | | | |
| **Operating Expenses (excluding cost of sales)** | | | | |
| Operating, general and administrative | $ 158.0 | $ 150.7 | $ 7.3 | 4.8 % |
| Property and other taxes | 94.8 | 91.5 | 3.3 | 3.6 |
| Depreciation and depletion | 93.8 | 90.0 | 3.8 | 4.2 |
| | **$ 346.6** | **$ 332.2** | **$ 14.4** | **4.3 %** |

Consolidated operating, general and administrative expenses were $158.0 million for the six months ended June 30, 2021, as compared with $150.7 million for the six months ended June 30, 2020. Primary components of the change include the following (in millions):

| | Operating, General & Administrative Expenses | |
|---|---|---|
| | 2021 vs. 2020 | |
| **Operating, General & Administrative Expenses Impacting Net Income** | | |
| Generation maintenance | $ | 1.7 |
| Employee benefits | | 1.4 |
| Technology implementation and maintenance | | 0.6 |
| Uncollectible accounts | | (4.4) |
| Travel and training | | (0.4) |
| Other | | 0.7 |
| **Change in Items Impacting Net Income** | | **(0.4)** |
| | | |
| **Operating, General & Administrative Expenses Offset Within Net Income** | | |
| Non-employee directors deferred compensation, offset in other income | | 5.3 |
| Pension and other postretirement benefits, offset in other income | | 2.4 |
| **Change in Operating, General & Administrative Expense Items Offset Within Net Income** | | **7.7** |
| **Increase in Operating, General & Administrative Expenses** | **$** | **7.3** |

Consolidated operating, general and administrative expenses increased $7.3 million, including a $0.4 million decrease from items impacting net income and a $7.7 million increase from items offset within net income.

The change in consolidated operating, general and administrative expenses for items impacting net income includes the following:

- Higher maintenance costs at our electric generation facilities;
- Higher employee benefit costs primarily due to an increase in medical benefits;
- Higher technology implementation and maintenance costs;
- Decreased uncollectible accounts due to collections of previously written off amounts in the current period. In the second quarter of 2020, we voluntarily suspended service disconnections for non-payment, to help customers who may be financially impacted by the COVID-19 pandemic; and
- A reduction in travel and training costs due to the impacts of the COVID-19 pandemic.

Property and other taxes were $94.8 million for the six months ended June 30, 2021, as compared with $91.5 million in the same period of 2020. This increase was due primarily to an increase in Montana state and local taxes. We estimate property taxes throughout each year, and update those estimates based on valuation reports received from the Montana Department of Revenue. Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and adjust our rates to recover the increase between rate cases less the amount allocated to FERC-jurisdictional customers and net of the associated income tax benefit.

Depreciation and depletion expense was $93.8 million for the six months ended June 30, 2021, as compared with $90.0 million in the same period of 2020. This increase was primarily due to plant additions.

Consolidated operating income for the six months ended June 30, 2021 was $140.0 million as compared with $120.1 million in the same period of 2020. This increase was primarily due to improved gross margin driven by higher Montana transmission loads and rates, a favorable electric QF liability adjustment as compared with the prior period, and favorable weather, partly offset by higher operating costs.

Consolidated interest expense was $47.0 million for the six months ended June 30, 2021 as compared with $48.6 million for the same period of 2020. This decrease was primarily due to higher capitalization of AFUDC, partly offset by higher borrowings.

Consolidated other income was $8.6 million for the six months ended June 30, 2021 as compared to consolidated other expense of $1.8 million during the same period of 2020. This increase includes approximately $7.7 million related to items offset in operating, general and administrative expense with no impact to net income and higher capitalization of AFUDC. Items offset in operating, general and administrative expense includes a $5.3 million increase in the value of deferred shares held in trust for non-employee directors deferred compensation and a decrease in other pension expense of $2.4 million.

Consolidated income tax expense for the six months ended June 30, 2021 was $1.3 million as compared to an income tax benefit of $2.5 million in the same period of 2020. Our effective tax rate for the six months ended June 30, 2021 was 1.3% as compared with (3.6)% for the same period in 2020. We expect our effective tax rate to range between (2.5)% to 2.5% in 2021.

The following table summarizes the differences between our effective tax rate and the federal statutory rate (in millions):

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2021 | | 2020 | |
| Income Before Income Taxes | $ 101.7 | | $ 69.7 | |
| Income tax calculated at federal statutory rate | 21.3 | 21.0 % | 14.6 | 21.0 % |
| Permanent or flow-through adjustments: | | | | |
| State income tax, net of federal provisions | 0.3 | 0.3 | 0.0 | 0.1 |
| Flow-through repairs deductions | (12.1) | (11.9) | (10.6) | (15.3) |
| Production tax credits | (6.6) | (6.5) | (5.3) | (7.7) |
| Plant and depreciation of flow-through items | (0.5) | (0.5) | 0.2 | 0.3 |
| Amortization of excess deferred income tax | (0.4) | (0.4) | (0.5) | (0.7) |
| Share-based compensation | (0.3) | (0.3) | (0.6) | (0.9) |
| Other, net | (0.4) | (0.4) | (0.3) | (0.4) |
| | (20.0) | (19.7) | (17.1) | (24.6) |
| **Income tax expense (benefit)** | $ 1.3 | 1.3 % | $ (2.5) | (3.6)% |

We compute income tax expense for each quarter based on the estimated annual effective tax rate for the year, adjusted for certain discrete items. Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through federal and state tax benefits of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits.

### *ELECTRIC SEGMENT*

We have various classifications of electric revenues, defined as follows:

- Retail: Sales of electricity to residential, commercial and industrial customers, and the impact of regulatory mechanisms.
- Regulatory amortization: Primarily represents timing differences for electric supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers, which is also reflected in cost of sales and therefore has minimal impact on gross margin. The amortization of these amounts are offset in retail revenue.
- Transmission: Reflects transmission revenues regulated by the FERC.
- Wholesale and other are largely gross margin neutral as they are offset by changes in cost of sales.

### Three Months Ended June 30, 2021 Compared with the Three Months Ended June 30, 2020

| | Revenues | | Change | | Megawatt Hours (MWH) | | Avg. Customer Counts | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | 2020 | $ | % | 2021 | 2020 | 2021 | 2020 |
| | (in thousands) | | | | | | | |
| Montana | $ 69,884 | $ 70,589 | $ (705) | (1.0) % | 575 | 577 | 311,264 | 306,797 |
| South Dakota | 14,401 | 14,597 | (196) | (1.3) | 119 | 123 | 50,734 | 50,660 |
| **Residential** | **84,285** | **85,186** | **(901)** | **(1.1)** | **694** | **700** | **361,998** | **357,457** |
| Montana | 84,555 | 77,426 | 7,129 | 9.2 | 762 | 684 | 71,400 | 69,837 |
| South Dakota | 24,053 | 23,190 | 863 | 3.7 | 252 | 243 | 12,805 | 12,830 |
| **Commercial** | **108,608** | **100,616** | **7,992** | **7.9** | **1,014** | **927** | **84,205** | **82,667** |
| Industrial | 9,224 | 9,192 | 32 | 0.3 | 618 | 730 | 77 | 78 |
| Other | 9,118 | 9,242 | (124) | (1.3) | 49 | 50 | 6,373 | 6,403 |
| **Total Retail Electric** | **$ 211,235** | **$ 204,236** | **$ 6,999** | **3.4 %** | **2,375** | **2,407** | **452,653** | **446,605** |
| Regulatory amortization | 5,201 | (116) | 5,317 | (4583.6) | | | | |
| Transmission | 23,862 | 12,895 | 10,967 | 85.0 | | | | |
| Wholesale and Other | 1,142 | 923 | 219 | 23.7 | | | | |
| **Total Revenues** | **$ 241,440** | **$ 217,938** | **$ 23,502** | **10.8 %** | | | | |
| **Total Cost of Sales** | **49,239** | **48,305** | **934** | **1.9** | | | | |
| **Gross Margin[(1)]** | **$ 192,201** | **$ 169,633** | **$ 22,568** | **13.3 %** | | | | |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

| | Cooling Degree Days | | | 2021 as compared with: | |
|---|---|---|---|---|---|
| | 2021 | 2020 | Historic Average | 2020 | Historic Average |
| Montana | 139 | 55 | 55 | 153% warmer | 153% warmer |
| South Dakota | 148 | 89 | 61 | 66% warmer | 143% warmer |

| | Heating Degree Days | | | 2021 as compared with: | |
|---|---|---|---|---|---|
| | 2021 | 2020 | Historic Average | 2020 | Historic Average |
| Montana | 1,167 | 1,227 | 1,164 | 5% warmer | remained flat |
| South Dakota | 1,365 | 1,464 | 1,487 | 7% warmer | 8% warmer |

The following summarizes the components of the changes in electric gross margin for the three months ended June 30, 2021 and 2020 (in millions):

| | | Gross Margin 2021 vs. 2020 |
|---|---|---|
| **Gross Margin Items Impacting Net Income** | | |
| Transmission | $ | 9.1 |
| Electric QF liability adjustment | | 6.1 |
| Retail volumes | | 5.6 |
| Montana electric supply cost recovery | | (0.8) |
| Other | | 0.8 |
| **Change in Gross Margin Impacting Net Income** | | 20.8 |
| | | |
| **Gross Margin Items Offset Within Net Income** | | |
| Operating expenses recovered in revenue, offset in operating expense | | 1.1 |
| Production tax credits reducing revenue, offset in income tax benefit | | 0.5 |
| Property taxes recovered in revenue, offset in property tax expense | | 0.2 |
| **Change in Gross Margin Items Offset Within Net Income** | | 1.8 |
| **Increase in Gross Margin(1)** | **$** | **22.6** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Gross margin increased $22.6 million, including a $20.8 million increase from items impacting net income and a $1.8 million increase from items offset within net income.

The change in gross margin for items impacting net income includes the following:

- Higher Montana transmission rates, the recognition of approximately $4.7 million of deferred interim revenues, and higher demand to transmit energy across our transmission lines due to market conditions and pricing;
- A more favorable adjustment of our electric QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) reflecting a $9.2 million gain in 2021, as compared with a $3.1 million gain for the same period in 2020, due to the combination of:
    - A $2.6 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $0.9 million favorable reduction in costs in the prior period;
    - A negative adjustment, increasing the QF liability by $2.1 million, reflecting annual actual contract price escalation, which was more than previously estimated, compared to a favorable adjustment of $2.2 million in the prior year due to lower actual price escalation; and
    - A favorable adjustment of approximately $8.7 million decreasing the QF liability due to a one-time clarification in contract term.
- An increase in electric retail revenue due to warmer spring weather, overall customer growth, and increased commercial volume as compared to the prior year. Residential retail volumes remained flat with warmer spring weather offset by lower usage than in the prior period; and
- Higher Montana electric supply costs as compared with the prior period.

The change in regulatory amortization revenue is due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers, which has a minimal impact on gross margin. In addition, while heating and cooling degree days may fluctuate significantly during the second quarter, our electric customer usage is not highly sensitive to these changes between the heating and cooling seasons. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

### Six Months Ended June 30, 2021 Compared with the Six Months Ended June 30, 2020

| | Revenues | | Change | | Megawatt Hours (MWH) | | Avg. Customer Counts | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | 2020 | $ | % | 2021 | 2020 | 2021 | 2020 |
| | (in thousands) | | | | | | | |
| Montana | $ 165,903 | $ 159,228 | $ 6,675 | 4.2 % | 1,375 | 1,310 | 310,750 | 306,384 |
| South Dakota | 32,150 | 33,515 | (1,365) | (4.1) | 295 | 303 | 50,770 | 50,651 |
| **Residential** | **198,053** | **192,743** | **5,310** | **2.8** | **1,670** | **1,613** | **361,520** | **357,035** |
| Montana | 171,396 | 163,432 | 7,964 | 4.9 | 1,551 | 1,476 | 71,273 | 69,764 |
| South Dakota | 48,171 | 49,685 | (1,514) | (3.0) | 530 | 534 | 12,763 | 12,782 |
| **Commercial** | **219,567** | **213,117** | **6,450** | **3.0** | **2,081** | **2,010** | **84,036** | **82,546** |
| Industrial | 18,939 | 17,951 | 988 | 5.5 | 1,231 | 1,405 | 77 | 78 |
| Other | 13,710 | 14,490 | (780) | (5.4) | 66 | 71 | 5,561 | 5,604 |
| **Total Retail Electric** | **$ 450,269** | **$ 438,301** | **$ 11,968** | **2.7 %** | **5,048** | **5,099** | **451,194** | **445,263** |
| Regulatory amortization | 19,991 | (3,749) | 23,740 | (633.2) | | | | |
| Transmission | 38,591 | 25,504 | 13,087 | 51.3 | | | | |
| Wholesale and Other | 2,660 | 2,507 | 153 | 6.1 | | | | |
| **Total Revenues** | **$ 511,511** | **$ 462,563** | **$ 48,948** | **10.6 %** | | | | |
| **Total Cost of Sales** | **129,427** | **112,139** | **17,288** | **15.4** | | | | |
| **Gross Margin[(1)]** | **$ 382,084** | **$ 350,424** | **$ 31,660** | **9.0 %** | | | | |

(1) Non-GAAP financial measure. See “Non-GAAP Financial Measure” above.

| | Cooling Degree Days | | | 2020 as compared with: | |
|---|---|---|---|---|---|
| | 2021 | 2020 | Historic Average | 2020 | Historic Average |
| Montana | 139 | 55 | 55 | 153% warmer | 153% warmer |
| South Dakota | 148 | 89 | 61 | 66% warmer | 143% warmer |

| | Heating Degree Days | | | 2021 as compared with: | |
|---|---|---|---|---|---|
| | 2021 | 2020 | Historic Average | 2020 | Historic Average |
| Montana | 4,429 | 4,355 | 4,457 | 2% cooler | 1% warmer |
| South Dakota | 5,165 | 5,493 | 5,561 | 6% warmer | 7% warmer |

The following summarizes the components of the changes in electric gross margin for the six months ended June 30, 2021 and 2020 (in millions):

| | | Gross Margin 2021 vs. 2020 |
|---|---|---|
| **Gross Margin Items Impacting Net Income** | | |
| Transmission | $ | 11.2 |
| Retail volumes | | 9.7 |
| Electric QF liability adjustment | | 6.1 |
| Montana electric supply cost recovery | | (2.2) |
| Other | | 3.2 |
| **Change in Gross Margin Impacting Net Income** | | 28.0 |
| | | |
| **Gross Margin Items Offset Within Net Income** | | |
| Property taxes recovered in revenue, offset in property tax expense | | 1.8 |
| Production tax credits reducing revenue, offset in income tax benefit | | 1.6 |
| Operating expenses recovered in revenue, offset in operating expense | | 0.3 |
| **Change in Gross Margin Items Offset Within Net Income** | | 3.7 |
| **Increase in Gross Margin[(1)]** | **$** | **31.7** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Gross margin increased $31.7 million, including a $28.0 million increase from items impacting net income and a $3.7 million increase from items offset within net income.

The change in gross margin for items impacting net income includes the following:

- Higher Montana transmission rates, the recognition of approximately$4.7 million of deferred interim revenues, and higher demand to transmit energy across our transmission lines due to market conditions and pricing;
- An increase in electric retail revenue driven by colder winter weather in Montana, warmer spring weather in both Montana and South Dakota, customer growth, and increased commercial volume as compared to the prior year due to the COVID-19 pandemic related shutdowns, partly offset by warmer winter weather in South Dakota;
- A more favorable adjustment of our electric QF liability (unrecoverable costs associated with PURPA contracts as part of a 2002 stipulation with the MPSC and other parties) reflecting a $9.2 million gain in 2021, as compared with a $3.1 million gain for the same period in 2020, due to the combination of:
  - A $2.6 million favorable reduction in costs for the current contract year to record the annual adjustment for actual output and pricing as compared with a $0.9 million favorable reduction in costs in the prior period;
  - A negative adjustment, increasing the QF liability by $2.1 million, reflecting annual actual contract price escalation, which was more than previously estimated, compared to a favorable adjustment of $2.2 million in the prior year due to lower actual price escalation; and
  - A favorable adjustment of approximately $8.7 million decreasing the QF liability due to a one-time clarification in contract term.
- Higher Montana electric supply costs as compared with the prior period.

The change in regulatory amortization revenue is due to timing differences between when we incur electric supply costs and when we recover these costs in rates from our customers, which has a minimal impact on gross margin. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

## *NATURAL GAS SEGMENT*

We have various classifications of natural gas revenues, defined as follows:

- Retail: Sales of natural gas to residential, commercial and industrial customers, and the impact of regulatory mechanisms.
- Regulatory amortization: Primarily represents timing differences for natural gas supply costs and property taxes between when we incur these costs and when we recover these costs in rates from our customers, which is also reflected in cost of sales and therefore has minimal impact on gross margin. The amortization of these amounts are offset in retail revenue.
- Wholesale: Primarily represents transportation and storage for others.

### Three Months Ended June 30, 2021 Compared with the Three Months Ended June 30, 2020

| | Revenues | | Change | | Dekatherms (Dkt) | | Avg. Customer Counts | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | 2020 | $ | % | 2021 | 2020 | 2021 | 2020 |
| | (in thousands) | | | | | | | |
| Montana | $ 25,503 | $ 17,483 | 8,020 | 45.9 % | 2,188 | 2,344 | 179,454 | 177,089 |
| South Dakota | 6,372 | 4,724 | 1,648 | 34.9 | 572 | 612 | 40,962 | 40,501 |
| Nebraska | 3,914 | 3,522 | 392 | 11.1 | 494 | 533 | 37,540 | 37,537 |
| **Residential** | **35,789** | **25,729** | **10,060** | **39.1** | **3,254** | **3,489** | **257,956** | **255,127** |
| Montana | 13,000 | 8,236 | 4,764 | 57.8 | 1,181 | 1,140 | 24,903 | 24,489 |
| South Dakota | 4,257 | 2,888 | 1,369 | 47.4 | 536 | 598 | 6,874 | 6,886 |
| Nebraska | 1,878 | 1,539 | 339 | 22.0 | 343 | 362 | 4,956 | 4,975 |
| **Commercial** | **19,135** | **12,663** | **6,472** | **51.1** | **2,060** | **2,100** | **36,733** | **36,350** |
| Industrial | 168 | 111 | 57 | 51.4 | 14 | 16 | 229 | 231 |
| Other | 355 | 177 | 178 | 100.6 | 42 | 30 | 163 | 152 |
| **Total Retail Gas** | **$ 55,447** | **$ 38,680** | **$ 16,767** | **43.3 %** | **5,370** | **5,635** | **295,081** | **291,860** |
| Regulatory amortization | (7,831) | 4,048 | (11,879) | (293.5) | | | | |
| Wholesale and other | 9,161 | 8,694 | 467 | 5.4 | | | | |
| **Total Revenues** | **$ 56,777** | **$ 51,422** | **$ 5,355** | **10.4 %** | | | | |
| **Total Cost of Sales** | **18,726** | **12,738** | **5,988** | **47.0** | | | | |
| **Gross Margin[(1)]** | **$ 38,051** | **$ 38,684** | **$ (633)** | **(1.6)%** | | | | |

(1) Non-GAAP financial measure. See “Non-GAAP Financial Measure” above.

| | Heating Degree Days | | | 2021 as compared with: | |
|---|---|---|---|---|---|
| | 2021 | 2020 | Historic Average | 2020 | Historic Average |
| Montana | 1,205 | 1,265 | 1,207 | 5% warmer | remained flat |
| South Dakota | 1,365 | 1,464 | 1,487 | 7% warmer | 8% warmer |
| Nebraska | 1,069 | 1,136 | 1,216 | 6% warmer | 12% warmer |

The following summarizes the components of the changes in natural gas gross margin for the three months ended June 30, 2021 and 2020:

| | | Gross Margin 2021 vs. 2020 |
|---|---|---|
| | | (in millions) |
| **Gross Margin Items Impacting Net Income** | | |
| Retail volumes | $ | (0.5) |
| Montana natural gas production rates | | (0.2) |
| Other | | 0.1 |
| **Change in Gross Margin Impacting Net Income** | | (0.6) |
| | | |
| **Gross Margin Items Offset Within Net Income** | | |
| Operating expenses recovered in trackers | | (0.3) |
| Gas production taxes | | 0.2 |
| Property tax revenue, offset in property tax expense | | 0.1 |
| **Change in Gross Margin Items Offset Within Net Income** | | — |
| **Decrease in Gross Margin[(1)]** | **$** | **(0.6)** |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

Gross margin decreased $0.6 million, including a $0.6 million decrease for items impacting net income. The items offset within net income offset one another for no impact to gross margin.

The change in gross margin for items impacting net income includes the following:

- A decrease in gas volumes due to warmer spring weather, partly offset by customer growth; and
- A reduction of rates from the step down of our Montana gas production assets.

Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

### Six Months Ended June 30, 2021 Compared with the Six Months Ended June 30, 2020

| | Revenues | | Change | | Dekatherms (Dkt) | | Avg. Customer Counts | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | 2020 | $ | % | 2021 | 2020 | 2021 | 2020 |
| | (in thousands) | | | | | | | |
| Montana | $ 72,514 | $ 55,778 | 16,736 | 30.0 % | 8,274 | 7,980 | 179,226 | 176,847 |
| South Dakota | 16,475 | 14,995 | 1,480 | 9.9 | 2,142 | 2,196 | 41,050 | 40,544 |
| Nebraska | 12,155 | 11,209 | 946 | 8.4 | 1,843 | 1,828 | 37,638 | 37,580 |
| **Residential** | **101,144** | **81,982** | **19,162** | **23.4** | **12,259** | **12,004** | **257,914** | **254,971** |
| Montana | 36,780 | 27,390 | 9,390 | 34.3 | 4,374 | 4,062 | 24,877 | 24,477 |
| South Dakota | 10,781 | 10,183 | 598 | 5.9 | 1,881 | 2,191 | 6,887 | 6,902 |
| Nebraska | 6,279 | 5,600 | 679 | 12.1 | 1,253 | 1,250 | 4,969 | 4,988 |
| **Commercial** | **53,840** | **43,173** | **10,667** | **24.7** | **7,508** | **7,503** | **36,733** | **36,367** |
| Industrial | 650 | 451 | 199 | 44.1 | 80 | 70 | 230 | 232 |
| Other | 844 | 520 | 324 | 62.3 | 118 | 93 | 161 | 152 |
| **Total Retail Gas** | **$ 156,478** | **$ 126,126** | **$ 30,352** | **24.1 %** | **19,965** | **19,670** | **295,038** | **291,722** |
| Regulatory amortization | 12,536 | (2,298) | 14,834 | (645.5) | | | | |
| Wholesale and other | 18,495 | 18,224 | 271 | 1.5 | | | | |
| **Total Revenues** | **$ 187,509** | **$ 142,052** | **$ 45,457** | **32.0 %** | | | | |
| **Total Cost of Sales** | **83,051** | **40,176** | **42,875** | **106.7** | | | | |
| **Gross Margin[(1)]** | **$ 104,458** | **$ 101,876** | **$ 2,582** | **2.5 %** | | | | |

(1) Non-GAAP financial measure. See "Non-GAAP Financial Measure" above.

| | Heating Degree Days | | | 2021 as compared with: | |
|---|---|---|---|---|---|
| | 2021 | 2020 | Historic Average | 2020 | Historic Average |
| Montana | 4,467 | 4,401 | 4,538 | 1% cooler | 2% warmer |
| South Dakota | 5,165 | 5,493 | 5,561 | 6% warmer | 7% warmer |
| Nebraska | 4,423 | 4,210 | 4,599 | 5% cooler | 4% warmer |

The following summarizes the components of the changes in natural gas gross margin for the six months ended June 30, 2021 and 2020:

| | Gross Margin 2021 vs. 2020 | |
|---|---|---|
| | (in millions) | |
| **Gross Margin Items Impacting Net Income** | | |
| Retail volumes | $ | 2.3 |
| Montana natural gas production rates | | (0.7) |
| Other | | 0.5 |
| **Change in Gross Margin Impacting Net Income** | | 2.1 |
| | | |
| **Gross Margin Items Offset Within Net Income** | | |
| Property tax revenue, offset in property tax expense | | 0.5 |
| Gas production taxes | | 0.2 |
| Operating expenses recovered in trackers | | (0.3) |
| **Change in Gross Margin Items Offset Within Net Income** | | 0.4 |
| **Increase in Gross Margin[(1)]** | **$** | **2.5** |

(1) Non-GAAP financial measure. See “Non-GAAP Financial Measure” above.

Gross margin increased $2.5 million, including a $2.1 million increase for items impacting net income and a $0.4 million increase from items offset within net income.

The change in gross margin for items impacting net income includes the following:

- An increase in gas volumes due to colder winter weather in our Montana and Nebraska jurisdictions and customer growth, partly offset by warmer winter weather in our South Dakota jurisdiction and warmer spring weather in all jurisdictions; and
- A reduction of rates from the step down of our Montana gas production assets.

Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

## LIQUIDITY AND CAPITAL RESOURCES

### Sources and Uses of Funds

We require liquidity to support and grow our business, and use our liquidity for working capital needs, capital expenditures, investments in or acquisitions of assets, and to repay debt. We believe our cash flows from operations, borrowing capacity under existing credit facilities, and issuance of debt or equity securities are sufficient to fund our operations, service existing debt, pay dividends, and fund capital expenditures (excluding strategic growth opportunities). The amount of capital expenditures and dividends are subject to certain factors including the use of existing cash, cash equivalents, the receipt of cash from operations, and available financing. A material change in operations, unfavorable credit metrics, or available financing could impact our current liquidity and ability to fund capital resource requirements, and we may defer a portion of our planned capital expenditures as necessary.

Our liquidity is supported by the use of our credit facilities which includes a $425 million Credit Facility and a $25 million revolving credit facility to provide swingline borrowing capability. The $425 million Credit Facility includes uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size by an additional $75 million with the consent of the lenders. The $425 million Credit Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to the Eurodollar rate, plus a margin of 112.5 to 175.0 basis points, or a base rate, plus a margin of 12.5 to 75.0 basis points. A total of ten banks participate in the facility, with no one bank providing more than 16 percent of the total availability. The $25 million revolving credit facility bears interest at the lower of prime plus a credit spread of 0.13 percent, or available rates tied to the Eurodollar rate plus a credit spread of 0.80 percent.

We utilize availability under our credit facilities to manage our cash flows due to the seasonality of our business, and utilize any cash on hand in excess of current operating requirements to invest in our business and reduce borrowings. As of June 30, 2021, our total net liquidity was approximately $145.9 million, including $5.9 million of cash and $140.0 million of revolving credit facility availability. As of June 30, 2021, there were no letters of credit outstanding and $310.0 million in outstanding borrowings under our credit facilities. Availability under our credit facilities was $143.0 million as of July 23, 2021.

We issue debt securities to refinance retiring maturities, fund construction programs and for other general corporate purposes. To fund our strategic growth opportunities, we utilize available cash flow, debt capacity and equity issuances that allow us to maintain investment grade ratings. We target a 50 - 55 percent debt to total capital ratio excluding finance leases, and a long-term dividend payout ratio target of 60 - 70 percent of earnings per share; however, there can be no assurance that we will be able to maintain our ratios within these target ranges.

In March 2021, we issued and sold $100 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 1.00% maturing in March 26, 2024. The net proceeds were used to repay in full our outstanding $100 million term loan that was due April 2, 2021. We may redeem some or all of the bonds at any time in whole, or from time to time in part, at our option, on or after March 26, 2022, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed, plus accrued and unpaid interest on the principal amount of the bonds being redeemed to, but excluding, the redemption date. The bonds are secured by our electric and natural gas assets in Montana and Wyoming.

In April 2021, we entered into an Equity Distribution Agreement pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an ATM program, including an equity forward sales component. During the three months ended June 30, 2021, we issued 879,309 shares of our common stock at an average price of $64.91, for net proceeds of $56.3 million, which is net of sales commissions and other fees paid of approximately $0.8 million. We expect to issue the remainder of the $200.0 million in 2021 to support our current capital program and maintain and protect our credit ratings. Capital investment in response to our Montana electric supply resource planning would be incremental to these amounts. Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

## Factors Impacting our Liquidity

*Supply Costs -* Our operations are subject to seasonal fluctuations in cash flow. During the heating season, which is primarily from November through March, cash receipts from natural gas and electric sales typically exceed cash requirements. During the summer months, cash on hand, together with the seasonal increase in cash flows and utilization of our existing revolver, are used to purchase natural gas to place in storage, perform maintenance, and make capital improvements. In addition, due to the lag between our purchases of electric and natural gas commodities and revenue receipt from customers, cyclical over and under collection situations arise consistent with the seasonal fluctuations discussed above; therefore we typically under collect in the fall and winter and over collect in the spring. Fluctuations in recoveries under our cost tracking mechanisms can have a significant effect on cash flows from operations and make year-to-year comparisons difficult.

We recover the cost of our electric and natural gas supply through tracking mechanisms. The natural gas supply tracking mechanism in each of our jurisdictions, and electric supply tracking mechanism in South Dakota are designed to provide stable recovery of supply costs, with a monthly adjustment to correct for any under or over collection. The Montana electric supply tracking mechanism implemented in 2018, the PCCAM, is designed for us to absorb risk through a sharing mechanism, with 90% of the variance above or below the established base revenues and actual costs collected from or refunded to customers. Our electric supply rates were adjusted monthly under the prior tracker, and under the PCCAM design are adjusted annually. In periods of significant fluctuation of loads and / or market prices, this design impacts our cash flows as application of the PCCAM requires that we absorb certain power cost increases before we are allowed to recover increases from customers.

As of June 30, 2021, we have under collected our costs recovered through tracking mechanisms by approximately $25.2 million. We under collected our costs by approximately $5.7 million as of December 31, 2020 and under collected our costs by approximately $12.8 million as of June 30, 2020.

## Credit Ratings

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are favorable to us and our customers, may impact our trade credit availability, and could result in the need to issue additional equity securities. Fitch Ratings (Fitch), Moody's Investors Service (Moody's), and S&P Global Ratings (S&P) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies' assessment of our ability to pay interest and principal when due on our debt. As of July 23, 2021, our current ratings with these agencies are as follows:

| | Senior Secured Rating | Senior Unsecured Rating | Commercial Paper | Outlook |
|---|---|---|---|---|
| Fitch | A | A- | F2 | Stable |
| Moody's[(1)] | A3 | Baa2 | Prime-2 | Negative |
| S&P | A- | BBB | A-2 | Stable |

(1) On March 12, 2021, Moody's affirmed our ratings, but revised our outlook from stable to negative citing rising debt to help fund higher capital expenditures and no substantive revenue increase over the next two to three years.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

## Cash Flows

The following table summarizes our consolidated cash flows (in millions):

| | Six Months Ended June 30, | |
|---|---|---|
| | 2021 | 2020 |
| **Operating Activities** | | |
| Net income | $ 100.3 | $ 72.2 |
| Non-cash adjustments to net income | 95.7 | 94.3 |
| Changes in working capital | (59.0) | 56.9 |
| Other noncurrent assets and liabilities | (32.5) | (4.2) |
| **Cash Provided by Operating Activities** | **104.5** | **219.2** |
| **Investing Activities** | | |
| Property, plant and equipment additions | (182.2) | (176.5) |
| Investment in equity securities | (0.6) | — |
| **Cash Used in Investing Activities** | **(182.8)** | **(176.5)** |
| **Financing Activities** | | |
| Proceeds from issuance of common stock, net | 56.3 | — |
| Issuance of long-term debt, net | 99.9 | 150.0 |
| (Repayments) issuance of short-term borrowings | (100.0) | 100.0 |
| Line of credit borrowings (repayments), net | 88.0 | (225.0) |
| Dividends on common stock | (62.8) | (60.2) |
| Financing costs | (0.6) | (1.1) |
| Other | — | (2.1) |
| **Cash Provided by (Used in) Financing Activities** | **80.8** | **(38.4)** |
| **Increase in Cash, Cash Equivalents, and Restricted Cash** | **2.5** | **4.3** |
| Cash, Cash Equivalents, and Restricted Cash, beginning of period | 17.1 | 12.1 |
| **Cash, Cash Equivalents, and Restricted Cash, end of period** | **$ 19.6** | **$ 16.4** |

### *Cash Provided by Operating Activities*

As of June 30, 2021, cash, cash equivalents, and restricted cash were $19.6 million as compared with $17.1 million at December 31, 2020 and $16.4 million at June 30, 2020. Cash provided by operating activities totaled $104.5 million for the six months ended June 30, 2021 as compared with $219.2 million during the six months ended June 30, 2020. This decrease in operating cash flows is primarily due to an $82.8 million increase in market purchases of supply during the February cold weather event resulting in an undercollection of supply costs from customers in the current period, and a refund of approximately $20.5 million to our FERC regulated wholesale customers.

### *Cash Used in Investing Activities*

Cash used in investing activities increased by approximately $6.3 million as compared with the first six months of 2020. Plant additions during the first six months of 2021 include maintenance additions of approximately $135.0 million and capacity related capital expenditures of $47.2 million. Plant additions during the first six months of 2020 included maintenance additions of approximately $114.4 million and capacity related capital expenditures of approximately $62.1 million.

### *Cash Provided by (Used in) Financing Activities*

Cash provided by financing activities totaled $80.8 million during the six months ended June 30, 2021 as compared with cash used in financing activities of $38.4 million during the six months ended June 30, 2020. During the six months ended June 30, 2021, cash provided by financing activities reflects net proceeds from the issuance of debt of $99.9 million, net issuances under our revolving lines of credit of $88.0 million, and proceeds received from the issuance of common stock pursuant to our ATM program of $56.3 million, offset in part by repayments of our short-term borrowings of $100.0 million and payment of dividends of $62.8 million. During the six months ended June 30, 2020, net cash used in financing activities reflects net repayments under our revolving lines of credit of $225.0 million and dividends of $60.2 million, offset in part by proceeds from the issuance of debt of $150.0 million and short term borrowings of $100.0 million.

### Capital Requirements

Our capital expenditures program is subject to continuing review and modification. Actual utility construction expenditures may vary from estimates due to changes in electric and natural gas projected load growth, changing business operating conditions and other business factors. We anticipate funding capital expenditures through cash flows from operations, available credit sources, debt and equity issuances. Our estimated capital expenditures are discussed in our Annual Report on Form 10-K for the year ended December 31, 2020 within the Management's Discussion and Analysis of Financial Condition and Results of Operations under the "Significant Infrastructure Investments and Initiatives" section. As of June 30, 2021, there have been no material changes in our estimated capital expenditures. If the MPSC approves our $250 million acquisition of the Laurel Generating Station, this project cost will be incremental to our current estimated capital expenditure program.

### Contractual Obligations and Other Commitments

We have a variety of contractual obligations and other commitments that require payment of cash at certain specified periods. The following table summarizes our contractual cash obligations and commitments as of June 30, 2021. See our Annual Report on Form 10-K for the year ended December 31, 2020 for additional discussion.

| | Total | 2021 | 2022 | 2023 | 2024 | 2025 | Thereafter |
|---|---|---|---|---|---|---|---|
| | | | | (in thousands) | | | |
| Long-term debt (1) | $ 2,516,637 | $ — | $ — | $ 454,660 | $ 100,000 | $ 300,000 | $ 1,661,977 |
| Finance leases | 16,155 | 2,026 | 2,875 | 3,097 | 3,338 | 3,596 | 1,223 |
| Estimated pension and other postretirement obligations (2) | 58,327 | 7,534 | 12,905 | 12,905 | 12,492 | 12,491 | NA |
| Qualifying facilities liability (3) | 503,566 | 39,054 | 80,355 | 82,452 | 73,933 | 59,180 | 168,592 |
| Supply and capacity contracts (4) | 2,411,756 | 158,728 | 207,523 | 232,102 | 195,272 | 190,226 | 1,427,905 |
| Contractual interest payments on debt (5) | 1,534,448 | 43,552 | 87,104 | 85,177 | 79,760 | 78,358 | 1,160,497 |
| **Total Commitments (6)** | $ 7,040,889 | $ 250,894 | $ 390,762 | $ 870,393 | $ 464,795 | $ 643,851 | $ 4,420,194 |

(1) Represents cash payments for long-term debt and excludes $13.3 million of debt discounts and debt issuance costs, net.
(2) We estimate cash obligations related to our pension and other postretirement benefit programs for five years, as it is not practicable to estimate thereafter. Pension and postretirement benefit estimates reflect our expected cash contributions, which may be in excess of minimum funding requirements.
(3) Certain QFs require us to purchase minimum amounts of energy at prices ranging from $42 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $503.6 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $418.5 million.
(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 26 years and exclude contract payments associated with the Beartooth Battery agreement, which is subject to approval by the MPSC.
(5) Contractual interest payments includes our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 1.36% on the outstanding balance through maturity of the facilities.
(6) The table above excludes potential tax payments related to uncertain tax positions as they are not practicable to estimate. Additionally, the table above excludes reserves for environmental remediation (See Note 10 - Commitments and Contingencies) and asset retirement obligations as the amount and timing of cash payments may be uncertain.

*Other Obligations -* As a co-owner of Colstrip, we provided surety bonds of approximately $19.9 million and $22.8 million as of June 30, 2021 and December 31, 2020, respectively, on behalf of the operator to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to

Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Stations, Colstrip Montana (the AOC) as required by the MDEQ. As costs are incurred under the AOC, the surety bonds will be reduced.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our Financial Statements, which have been prepared in accordance with GAAP. The preparation of these Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and other assumptions that are believed to be proper and reasonable under the circumstances.

We continually evaluate the appropriateness of our estimates and assumptions. Actual results could differ from those estimates. We consider an estimate to be critical if it is material to the Financial Statements and it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate are reasonably likely to occur from period to period. This includes the accounting for the following: regulatory assets and liabilities, pension and postretirement benefit plans, income taxes and qualifying facilities liability. These policies were disclosed in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2020. As of June 30, 2021, there have been no material changes in these policies.

## ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks, including, but not limited to, interest rates, energy commodity price volatility, and counterparty credit exposure. Management has established comprehensive risk management policies and procedures to manage these market risks. There have been no material changes in our market risks as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2020.

## ITEM 4. CONTROLS AND PROCEDURES

**Evaluation of Disclosure Controls and Procedures**

We have established disclosure controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and accumulated and reported to management, including the principal executive officer and principal financial officer to allow timely decisions regarding required disclosure.

We conducted an evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on this evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective.

**Changes in Internal Control Over Financial Reporting**

There have been no changes in our internal control over financial reporting during the most recent fiscal quarter 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

See Note 10, Commitments and Contingencies, to the Financial Statements for information regarding legal proceedings.

### ITEM 1A. RISK FACTORS

You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities. Although the risks are organized by headings and each risk is described separately, many of the risks are interrelated.

### COVID-19 Risks

**The COVID-19 pandemic and resulting adverse economic conditions have had, and we expect are likely to continue to have, a negative impact on our business, financial condition and results of operations.**

The COVID-19 pandemic has had widespread impacts on people, economies, businesses and financial markets. The continuing impact of the COVID-19 pandemic is highly uncertain and subject to change, and also depends on factors beyond our knowledge or control, including the ultimate duration and severity of this outbreak, third-party actions taken to contain its spread and mitigate its public health effects, and possible federal or state legislative actions related to utility operations, including disconnect moratoriums, or additional economic stimulus packages. In addition, we cannot predict the ongoing and ultimate impact that the COVID-19 pandemic will have on our customers, suppliers, vendors, and other business partners, and each of their financial conditions; however, any material effect on these parties could adversely impact us.

Economic - The COVID-19 pandemic continues to be an evolving situation with an extended disruption of economic activity. Our financial results in 2020 were impacted by lower sales volumes, an increase in reserves for uncollectible accounts and an increase in interest expense, partly offset by lower operating, general and administrative expenses. Decreases in per capita income and level of disposable income, increased unemployment or a decline in consumer confidence have had and could continue to have an adverse effect on our business. Certain of our customers have been, and may again in the future be, required to close down or operate at a lower capacity, which has adversely impacted our business in the short term and may in the future materially adversely affect our business, financial condition and results of operations. While the impact of the COVID-19 pandemic has eased during 2021 and we have experienced improvements in our financial results, there can be no assurance that any decrease in revenues resulting from the COVID-19 pandemic will return to previous levels in the future. In addition, we continue to monitor the capital markets. If conditions deteriorate and disrupt the capital markets and we need to access capital, there can be no assurance that we will be able to obtain such financing on commercially reasonable terms or at all.

Operational - While the COVID-19 pandemic has not caused material disruptions to our operations, it could in the future as a result of, among other things, quarantines, increased cyber risk due to employees working from home, worker absenteeism as a result of illness or other factors, social distancing measures and other travel, health-related, business or other restrictions. If a significant percentage of our workforce is unable to work, including because of illness, travel restrictions, or government mandates in connection with pandemics or disease outbreaks, our operations may be negatively affected. In addition, remote work arrangements introduce operational risk, including but not limited to cybersecurity risks.

For similar reasons, the COVID-19 pandemic may similarly adversely impact our suppliers and their manufacturers. Depending on the extent and duration of COVID-19 pandemic's effects on our business and operations and the business and operations of our suppliers, our costs could increase, including our costs to address the health and safety of personnel, and our ability to obtain certain supplies or services.

National, state and local governments have responded to the COVID-19 pandemic in a variety of ways, including, without limitation, by declaring states of emergency, restricting people from gathering in groups or interacting within a certain physical distance (i.e., social distancing), and in certain cases, ordering businesses to close or limit operations or people to stay at home. While there has been a general easing of restrictions through 2021, there can be no guarantee that this trend will continue.

Although we provide critical infrastructure services and are permitted to continue to operate in each of our jurisdictions, there may be restrictions imposed on how we operate, such as disconnect moratoriums.

Any such workforce implications, significant supply chain disruptions, and / or limitations or closures may impact our ability to achieve our capital investment program and could have a material adverse impact on our ability to serve our customers and on our business, financial condition and results of operations.

***The impacts of the COVID-19 pandemic may also have the effect of heightening risks discussed below, any of which could have a material effect on us.***

## Regulatory, Legislative and Legal Risks

**Our profitability is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We are subject to potential unfavorable state and federal regulatory outcomes. To the extent our incurred costs are deemed imprudent by the applicable regulatory commissions or certain regulatory mechanisms are not available, we may not recover some of our costs, which could adversely impact our results of operations and liquidity.**

We provide service at rates established by several regulatory commissions. Rates are generally set through a process called a rate review (or rate case) in which the utility commission analyzes our costs incurred during a historical test year and decides whether they may be included in our rates. Rate reviews can be highly contested proceedings. There is no guarantee that the costs we seek to recover in future rates will be allowed. There is also typically a significant lag between the time we incur a cost and recover that cost in rates.

In addition to rate cases, our cost tracking mechanisms are a significant component of how we recover our costs. Trackers can also be highly contested dockets and, as with a rate case, there is no guarantee that the regulatory commission will approve our request to recover costs. We have recently received, and may in the future receive, unfavorable rulings from the MPSC. During the fourth quarter of 2020, the MPSC disallowed approximately $9.4 million of power costs for the July 1, 2018 to June 30, 2019 time period related to an intermittent outage at Colstrip Units 3 and 4 and application of a change in state laws addressing cost sharing of power costs. There can be no assurance that the MPSC will allow recovery of costs in the future, which could have a material adverse effect on our financial results.

Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital. In a continued low interest rate environment there has been downward pressure on return on equity. There also can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. In addition, each regulatory commission sets rates based in part upon their acceptance of an allocated share of total utility costs. When commissions adopt different methods to calculate inter-jurisdictional cost allocations, some costs may not be recovered. For instance, our Montana electric utility is regulated by the MPSC and the FERC. Differing schedules and regulatory practices between the MPSC and FERC expose us to the risk that we may not recover our costs due to timing of filings and issues such as cost allocation methodologies. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Adverse regulatory rulings could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock.

**We are subject to changing federal and state laws and regulations. Congress and state legislatures may enact legislation that adversely affects our operations and financial results.**

We are subject to regulations under a wide variety of U.S. federal and state regulations and policies. Regulation affects almost every aspect of our business. Changes to federal and state laws and regulations are continuous and ongoing and the Biden Administration, the U.S. Congress, and state legislatures and state administrations may enact and implement new laws and regulations that could adversely and materially affect us. There can be no assurance that laws, regulations and policies will not be changed in ways that result in significant impacts to our business. We cannot predict future changes in laws and regulations, how they will be implemented and interpreted, or the ultimate effect that this changing environment will have on us. Any changes may have a material adverse effect on our financial condition, results of operations, and cash flows.

**We are subject to extensive and changing energy, and environmental laws and regulations, including legislative and regulatory responses to climate change, with which compliance may be difficult and costly.**

Our operations are subject to laws and regulations imposed by federal, state and local government authorities regarding energy policy, climate change, the environment, air and water quality, GHG emissions, protection of natural resources, migratory birds and other wildlife, solid waste disposal, coal ash and other environmental considerations. We believe that we are in compliance with environmental regulatory requirements.

However, laws and regulations to which we must adhere change, and the Biden Administration's agenda represents a significant shift in environmental and energy policy, focusing on reducing GHG emissions and climate change issues. This new direction is reflected in several Executive Orders that President Biden issued in January 2021. Together, these orders reflect climate change issues and GHG reductions as central areas of focus for domestic and international regulations, orders and policies. In addition, a parallel focus on reducing GHG emissions is reflected in legislation introduced in March 2021 in the U.S. House of Representatives, called the CLEAN Future Act. We expect other legislation to be introduced and considered by the U.S. House and the U.S. Senate focusing on environmental and energy policy.

These initiatives will likely lead to new and revised energy and environmental laws and regulations. Any such changes, as well as any enforcement actions or judicial decisions regarding those laws and regulations, could affect our costs and the manner in which we conduct our business and could require us to make substantial additional capital expenditures or abandon certain projects.

In addition, although previous attempts by the EPA to regulate GHG emissions from coal-fired plants have not succeeded, it is widely expected that the Biden Administration and/or the U.S. Congress will develop an alternative plan for reducing GHG emissions from coal-fired plants and methane emissions from natural gas operations. As GHG and/or methane regulations are implemented, it could result in additional compliance costs that could affect our future results of operations and financial position if such costs are not recovered through regulated rates. Complying with the $CO_2$ emission performance standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources.

To the extent that costs exceed our estimated environmental liabilities, or we are not successful in recovering remediation costs or costs to comply with the proposed or any future changes in rules or regulations, our results of operations and financial position could be adversely affected. Certain environmental laws and regulations also provide for substantial civil and criminal fines for noncompliance which, if imposed, could result in material costs or liabilities.

In addition, there is a risk of environmental damage claims from private parties or government entities. We may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws.

**Early closure of our owned and jointly owned electric generating facilities due to environmental risks, litigation or public policy changes could have a material adverse impact on our results of operations and liquidity.**

While our Company-wide electric supply portfolio is over 65 percent carbon-free, it does include fossil-fuel resources. Environmental advocacy groups, certain investors and other third parties oppose the operation of fossil-fuel generation, expressing concerns about the environmental and climate-related impacts from fossil fuels. This opposition may increase in scope and frequency depending on a number of variables, including the course of Federal and State laws and environmental regulations and the financial resources devoted to opposition efforts. These risks include litigation against us due to GHG or other emissions or coal combustion residuals disposal and storage; activist shareholder proposals; and increased activism before our regulators. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities. In addition, defense costs associated with litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

Early closure of our generation facilities due to economic conditions, environmental regulations and / or litigation could result in regulatory impairments, increased cost of operations and inability to serve our customers in periods of peak demand. If recovery of our remaining investment in such facilities and the costs associated with early closure, including decommissioning, remediation, reclamation, and restoration are not recovered from customers, it could have a material adverse impact on our results of operations.

Colstrip - As part of the settlement of litigation brought by the Sierra Club and the Montana Environmental Information Center against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding those units, including their shut down, were made by their respective owners. The six owners of Units 3 and 4 currently share the operating costs pursuant to the terms of the O&O Agreement. Costs of common facilities were historically shared among the owners of all four units. With the closure of Units 1 and 2, we are incurring additional operating costs with respect to our interest in Unit 4 and expect to experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines. We would expect to incorporate any reduction in revenue in our next general electric rate filing, resulting in lower revenue credits to certain customers.

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Recovery of costs associated with the closure of the facility is subject to MPSC approval. Three of the joint owners of Units 3 and 4 are subject to regulation in Washington and in May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to "eliminate coal-fired resources from [their] allocation of electricity" on or before December 31, 2025, after which date they may no longer include their share of coal-fired resources in their regulated electric supply portfolio. As a result of the Washington legislation, four of the six joint owners of Units 3 and 4 requested the operator prepare a 2021 budget reflecting closure of Units 3 and 4 by 2025, and alternately a closure of Unit 3 by 2025 and a closure of Unit 4 by 2027. Differing viewpoints on closure dates delayed approval of the 2021 budget, until it was approved on March 22, 2021. We anticipate the annual budgeting process for Units 3 and 4 may raise similar efforts to tie budgeting to a closure date, resulting in future budgets that may not be sufficient to maintain the reliability of Units 3 and 4.

While we believe closure requires each owner's consent, there are differences among the owners as to this issue under the O&O Agreement. On March 12, 2021, we initiated The Arbitration under the O&O Agreement, which seeks to resolve the primary issue of whether closure of Units 3 and 4 can be accomplished without each joint owner's consent and to clarify the obligations of the joint owners to continue to fund operations until all joint owners agree on closure.

The Arbitration has given rise to three lawsuits, concerning the number of arbitrators, the venue and the applicable arbitration laws. The four joint owners from the Pacific Northwest assert the Arbitration must be conducted under the O&O Agreement, with one arbitrator, in Spokane County, Washington, and pursuant to the Washington Arbitration Act. The fifth joint owner asserts the Arbitration must be conducted per the terms of Montana Senate Bill 265, which requires the Arbitration must be conducted, with three arbitrators, in Montana and pursuant to the Montana Uniform Arbitration Act. The three initiated lawsuits do not make direct financial demands, and instead, are intended to address issues related to process for the Arbitration.

Since the Arbitration was initiated, and despite the litigation, we have worked and continue to work with the other joint owners to arrive at an agreed up process for the Arbitration.

In response to a letter from several non-governmental organizations, the Washington Utilities and Transportation Commission (WUTC) issued a Notice of Opportunity to Respond to Request to Initiate Investigation on April 13, 2021, in which it sought comment on whether it should "'initiate a proceeding to investigate Colstrip's ongoing expenses' resulting in a 'clear order or determination from the [WUTC] that continued funding to maintain and operate Colstrip is not consistent with prudent utility practice.'" While the WUTC denied to initiate the requested investigation, this reflects that efforts to close Colstrip Units 3 and 4 continue.

In addition, we have joint ownership in and operate the associated 500 kV transmission system. The closure of generation at Colstrip may impact the operation of this 500 kV system, and the joint owners may have differing needs with regard to ongoing operation of this system. The 500 kV transmission system is an integral, essential part of our overall transmission system in Montana in order to maintain reliability, regardless of the status of the generation facilities.

**Increased risks of regulatory penalties could negatively impact our business.**

We must comply with established reliability standards and requirements including Critical Infrastructure Protection Reliability Standards, which apply to North American Electric Reliability Corporation (NERC) functions. NERC reliability standards protect the nations' bulk power system against potential disruptions from cyber and physical security breaches. The FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity that violates their rules, regulations or standards. Penalties for the most severe violations can reach as high as approximately $1.2 million per violation, per day. If a serious reliability incident or other incidence of noncompliance did occur, it could have a material adverse effect on our operating and financial results.

Additionally, the Pipeline and Hazardous Materials Safety Administration, Occupational Safety and Health Administration and other federal or state agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

**Federally mandated purchases of power from QFs, and integration of power generated from those projects in our system, may increase costs to our customers and decrease system reliability, limit our ability to make generation investments and adversely affect our business.**

We are generally obligated under federal law to purchase power from certain QF projects, regardless of current load demand, availability of lower cost generation resources, transmission availability or market prices. These resources are primarily intermittent, non-dispatchable generation whose prices may be in excess of market prices during times of lower customer demand, and may not be able to generate electricity during peak times. These resources typically do not meet the requirements set forth in our supply plans for resource procurement. These requirements to purchase supply that is inconsistent with customer need may have several impacts, including increasing the likelihood and frequency that we will be required to reduce output from owned generation resources and that we will need to upgrade or build additional transmission facilities to serve QF projects. Either of these results would increase costs to customers. Further, balancing load and power generation on our system is challenging, and we expect that operational costs will increase as a result of integration of these intermittent, non-dispatchable generation projects. If we are unable to timely recover those costs through our PCCAM or otherwise, those increased costs may negatively affect our liquidity, results of operations and financial condition.

In addition, requirements to procure power from these sources could impact our ability to make generation investments depending upon the number and size of QF contracts we ultimately enter into. The cost to procure power from these QFs may not be a cost effective resource for customers, or the type of generation resource needed, resulting in increased supply costs that are inconsistent with resource plans developed based on a lowest cost and least risk basis while placing upward pressure on overall customer bills. This may impact our investment plans and financial condition. Finally, the requirement to procure power from these QF sources may impact our transmission system and require additional transmission facilities to be developed in order to integrate these resources, which also can impact overall customer bills.

## Operational Risks

**Our electric and natural gas operations involve numerous activities that may result in accidents, fires, system outages and other operating risks and costs that are unique to our industry.**

Inherent in our electric transmission and distribution and natural gas transportation and distribution operations are a variety of hazards and operating risks, such as breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, and catastrophic events such as fires, electric contacts, leaks, explosions, floods and intentional acts of destruction. These risks could cause a loss of human life, facility shutdown or significant damage to property, loss of customer load, environmental pollution, impairment of our operations, and substantial financial losses to us and others. For our natural gas lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of potential damages resulting from these risks could be significant.

Our electric distribution and transmission lines and facilities are exposed to many threats that may impact our infrastructure, as discussed above. These include severe weather, along with accidental and intentional acts that may cause our lines to fail. In addition, tree mortality rates have increased resulting in hazard trees located inside or outside our lines' rights of way. Hazard trees are those trees that are structurally unsound and could fall into our lines if the trees failed. We are facing challenges to address these trees. The risk of fires is exacerbated in forested areas where there has been a significant increase in the quantity of standing dead and dying timber, primarily as a result of beetle infestation, increasing the risk that such trees may fall from either inside or outside our right-of-way into a power line igniting a fire. The fire risk in the Western states is heightened due to extreme drought and high temperatures. Fires alleged to have been caused by our system could expose us to significant penalties and / or damage claims on theories such as strict liability, negligence, gross negligence, trespass, inverse condemnation, and others.

For our electric generating facilities, operational risks include facility shutdowns due to breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities; and operational changes necessitated by environmental legislation, litigation or regulation. The loss of a major electric generating facility would require us to find other sources of supply or ancillary services, if available, and expose us to higher purchased power costs and potential litigation which may not be recovered from customers.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

**We may have difficulty completing certain operations activities and construction projects if our third-party business partners are unable to deliver ordered supplies or complete contracted services timely.**

We place significant reliance on our third-party business partners to supply materials, equipment and labor necessary for us to operate our utility and reliably serve current customers and future customers. As a result of current macroeconomic conditions, both nationally and globally, we have recently experienced issues with our supply chain for materials and components used in our operations and capital project construction activities. Issues include higher prices, scarcities/shortages, and longer fulfillment times for orders from our suppliers. Should these economic conditions and issues continue, we could have difficulty completing the operations activities necessary to serve our customers safely and reliably, and/or achieving our capital investment program, which could have a material adverse impact on our business, financial condition and results of operations.

**Cyber and physical attacks, threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may affect our operations in unpredictable ways and could adversely affect our liquidity and results of operations. Failure to maintain the security of personally identifiable information could adversely affect us.**

Business Operations - We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber attacks, physical security breaches and other disruptive activities of individuals or groups, and theft of our critical infrastructure information. Our generation, transmission and distribution facilities are deemed critical infrastructure and provide the framework for our service infrastructure. Cyber crime, which includes the use of malware, phishing attempts, computer viruses, and other means for disruption or unauthorized access has increased in frequency, scope, and potential impact in recent years. Our assets and the information technology systems on which they depend could be direct targets of, or indirectly affected by, cyber attacks and other disruptive activities, including those that impact third party facilities that are interconnected to us. Any significant interruption of these assets or systems could prevent us from fulfilling our critical business functions including delivering energy to our customers, and sensitive, confidential and other data could be compromised.

Security threats continue to evolve and adapt and the risk of cyber-based attacks is heightened with many of our employees working and accessing our technology infrastructure remotely as a result of the COVID-19 pandemic. We and our third-party vendors have been subject to, and will likely continue to be subject to, attempts to gain unauthorized access to systems, to confidential data, or to disrupt operations. With the continuing rise in ransomware and other cyber-based threats we have been analyzing our technology platforms and monitoring for signs of potential intrusions. We have also been reaching out to our vendors, suppliers and contractors requesting that they take appropriate measures. None of these attempts has individually or in the aggregate resulted in a security incident with a material impact on our financial condition or results of operations. However, despite implementation of security and control measures, there can be no assurance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact.

These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure assets, and could adversely affect our operations by contributing to the disruption of supplies and markets for electricity, natural gas, oil and other fuels. These events could also impair our ability to raise capital by contributing to financial instability and reduced economic activity.

Personally Identifiable Information - Our information systems and those of our third-party vendors contain confidential information, including information about customers and employees. Customers, shareholders, and employees expect that we will adequately protect their personal information. The regulatory environment surrounding information security and privacy is increasingly demanding. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject us to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm our reputation.

We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

**Weather and weather patterns, including normal seasonal and quarterly fluctuations of weather, as well as extreme weather events that might be associated with climate change, could adversely affect our ability to manage our operational requirements to serve our customers, and ultimately adversely affect our results of operations and liquidity.**

Our electric and natural gas utility business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for electricity and natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenue and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters or cool summers could adversely affect our results of operations and financial position. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for electricity and natural gas. Our sensitivity to weather volatility is significant due to the absence of regulatory mechanisms, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs.

Severe weather impacts, including but not limited to, blizzards, thunderstorms, high winds, microbursts, fires, tornadoes and snow or ice storms can disrupt energy generation, transmission and distribution. We derive a significant portion of our energy supply from hydroelectric facilities, and the availability of water can significantly affect operations. Higher temperatures may decrease the Montana snowpack and impact the timing of run-off and may require us to purchase replacement power. Dry conditions, which exist in the West and in our service territory, also increase the threat of fires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, fires that are alleged to have been caused by our system could expose us to substantial property damage and other claims. Any damage caused as a result of fires could negatively impact our financial condition, results of operations or cash flows.

There is also a concern that the physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate.

Extreme weather conditions, especially those of prolonged duration, create high energy demand on our own and/or other systems and increase the risk we may be unable to reliably serve customers, causing brownouts and/or blackouts of our electric systems, and loss of gas supply. Risk of losing electricity or gas supply during extreme weather carries significant consequences as without our services our customers may be subjected to dire circumstances. Additionally, extreme weather conditions may raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks.

**Our electric and natural gas portfolios rely significantly on market purchases. This exposure adversely affects our ability to manage our operational requirements to serve our customers, while exposing us to market volatility, which ultimately could adversely affect our results of operations and liquidity.**

We are obligated to supply power to retail customers and certain wholesale customers and procure natural gas to supply fuel for our natural gas fired generation. Our need to acquire flexible energy supply and capacity in the market to meet our electric and natural gas load serving obligations exposes us to certain risks including the ability to reliably serve customers and significant uncertainty in the cost of supply, which may not be recoverable. We rely upon a combination of base-load supply from our owned generation and market purchases to serve customers. In Montana, we have significant projected generation capacity deficits and negative reserve margins. Based on recent estimates, we forecast that our portfolio will be 725 MW short by 2025, considering expiring contracts and a modest increase in customer demand. Approximately 46 percent of our peak electric requirements are served through market purchases. Montana has been a net exporter of electric generation and we have relied upon Montana's excess generation for grid reliability and to physically serve customers. A significant number of base-load generation facilities, which may also serve to meet peak requirements, in the state and region have been retired or are scheduled to be retired in the next five to ten years. This includes Colstrip Units 1 and 2, representing 614 MWs of generation on a capacity basis, which ceased operations in January 2020. A decrease in the state and region’s electric capacity may impair the reliability of the grid, particularly during peak demand periods. There can be no assurance that there will be available counterparties to contract with to serve our customers' needs, or that these counterparties will fulfill their obligations to us. There is also no assurance that the transmission capacity required to import market purchases will be available on transmission systems owned by us or by third parties. In addition, the suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us. These conditions could result in an inability to physically deliver electricity to our customers. Losing electric service during extreme conditions carries significant consequences, as without our services our customers may be subjected to dire circumstances.

Commodity pricing is an inherent risk component of our business operations and our financial results. Even though rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our costs are recoverable as discussed above. The prevailing market prices for electricity may fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition and cash flows due to our need for market purchases and the sharing component of the Montana PCCAM.

In addition, our natural gas system serves both retail customers and the needs of natural gas fired electric generation. The natural gas system has capacity constraints that expose us to risks to be able to deliver natural gas during periods of peak demand.

Fluctuations in actual weather conditions, generation availability, transmission constraints, and generation reserve margins may all have an impact on market prices for energy and capacity and the electricity consumption of our customers on a given day. Extreme weather conditions may force us to purchase electricity in the short-term market on days when weather is unexpectedly severe, and the pricing for market energy may be significantly higher on such days than the cost of electricity in our existing generation and contracts. Unusually mild weather conditions could leave us with excess power which may be sold in the market at a loss if the market price is lower than the cost of electricity in our existing contracts.

**Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions or response to price increases. We are also impacted by market conditions outside of our service territories related to demand for transmission capacity and wholesale electric pricing.**

Our revenues, results of operations and financial condition are impacted by customer growth and usage, which can be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in their disposable income, and the use of distributed generation resources or other emerging technologies for electricity. Advances in distributed generation technologies that produce power, including fuel cells, micro-turbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production. Customer-owned generation itself reduces the amount of electricity purchased from utilities and may have the effect of inappropriately increasing rates generally and increasing rates for customers who do not own generation, unless retail rates are designed to collect distribution grid costs across all customers in a manner that reflects the benefit from their use. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy.

Decreasing use per customer (driven, for example, by appliance and lighting efficiency) and the availability of cost-effective distributed generation, put downward pressure on load growth. Our most recent resource plans include an expected annual load growth assumption of 0.4 percent in Montana and 0.7 percent in South Dakota, which reflects low customer and usage increases, offset in part by these load reduction measures. Reductions in usage, attributable to various factors could materially affect our results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Demand for our Montana transmission capacity fluctuates with regional demand, fuel prices and weather related conditions. The levels of wholesale sales depend on the wholesale market price, market participants, transmission availability, the availability of generation, and the ongoing development of the Western Energy Imbalance Market, among other factors. Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce wholesale sales. These events could adversely affect our results of operations, financial position and cash flows.

## Liquidity and Financial Risks

**Our plans for future expansion through the acquisition of assets, capital improvements to existing assets, generation investments, and transmission grid expansion involve substantial risks.**

Acquisitions include a number of risks, including but not limited to, regulatory approval, regulatory conditions, additional costs, the assumption of material liabilities, the diversion of management's attention from daily operations to the integration of the acquisition, difficulties in assimilation and retention of employees, and securing adequate capital to support the transaction. The regulatory process in which rates are determined may not result in rates that produce full recovery of our investments, or a reasonable rate of return. Uncertainties also exist in assessing the value, risks, profitability, and liabilities associated with certain businesses or assets and there is a possibility that anticipated operating and financial synergies expected to result from an acquisition do not develop. The failure to successfully integrate future acquisitions that we may choose to undertake could have an adverse effect on our financial condition and results of operations.

Our business strategy also includes significant investment in capital improvements and additions to modernize existing infrastructure, generation investments and transmission capacity expansion. The completion of generation and natural gas investments and transmission projects are subject to many construction and development risks, including, but not limited to, risks related to permitting, financing, regulatory recovery, escalating costs of materials and labor, meeting construction budgets and schedules, and environmental compliance. In addition, these capital projects may require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support such projects. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital.

**We must meet certain credit quality standards. If we are unable to maintain investment grade credit ratings, our liquidity, access to capital and operations could be materially adversely affected.**

A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and would increase our borrowing costs. Higher interest rates on borrowings with variable interest rates could also have an adverse effect on our results of operations.

**Poor investment performance of plan assets of our defined benefit pension and postretirement benefit plans, in addition to other factors impacting these costs, could unfavorably impact our results of operations and liquidity.**

Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors. Assumptions related to future costs, return on investments and interest rates have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance and changes in governmental regulations. Without sustained growth in the plan assets over time and depending upon interest rate changes as well as other factors noted above, the costs of such plans reflected in our results of operations and financial position and cash funding obligations may change significantly from projections.

**Our obligation to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH could expose us to material commodity price risk if certain QFs under contract with us do not perform during a time of high commodity prices, as we are required to make up the difference. In addition, we are subject to price escalation risk with one of the largest QF contracts.**

As part of a stipulation in 2002 with the MPSC and other parties, we agreed to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH through June 2029. This obligation is reflected in the electric QF liability, which reflects the unrecoverable costs associated with these specific QF contracts per the stipulation. The annual minimum energy requirement is achievable under normal operations of these facilities, including normal periods of planned and forced outages. However, to the extent the supplied power for any year does not reach the minimum quantity set forth in the settlement, we are obligated to purchase the difference from other sources. The anticipated source for any shortfall is the wholesale market, which would subject us to commodity price risk if the cost of replacement power is higher than contracted rates.

In addition, we are subject to price escalation risk with one of the largest contracts included in the electric QF liability due to variable contract terms. In recording the electric QF liability, we estimated an annual escalation rate of three percent over the remaining term of the contract (through June 2024). To the extent the annual escalation rate exceeds three percent, our results of operations, cash flows and financial position could be adversely affected.

**ITEM 6. EXHIBITS -**

(a) Exhibits

Exhibit 10.1 — Equity Distribution Agreement, dated April 23, 2021, between NorthWestern Corporation and J.P. Morgan Securities LLC, BofA Securities, Inc., CIBC World Markets Corp. and Credit Suisse Securities (USA) LLC, as sales agents and forward sellers; and JPMorgan Chase Bank, National Association, Bank of America N.A, Canadian Imperial Bank of Commerce and Credit Suisse Capital LLC, as forward purchasers. (incorporated by reference of Exhibit 1.1 of NorthWestern Corporation's Current Report on Form 8-K, dated April 23, 2021, Commission File No. 1-10499).

Exhibit 10.2 — Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 of Northwestern Corporation's Current Report on From 8-K, dated April 23, 2021, Commission File No. 1-10499)

Exhibit 10.3 — Engineering, Procurement, and Construction Contract, dated April 19, 2021, between Northwestern Energy and Burns & McDonnell Engineering Company, Inc.

Exhibit 10.4 — Procurement Contract, dated April 19, 2021, between Northwestern Energy and Caterpillar Power Generation Systems, LLC.

Exhibit 31.1—Certification of chief executive officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002.

Exhibit 31.2—Certification of chief financial officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002.

Exhibit 32.1—Certification of chief executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.2—Certification of chief financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 101.INS—Inline 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.

Exhibit 101.SCH—Inline XBRL Taxonomy Extension Schema Document

Exhibit 101.CAL—Inline XBRL Taxonomy Extension Calculation Linkbase Document

Exhibit 101.DEF—Inline XBRL Taxonomy Extension Definition Linkbase Document

Exhibit 101.LAB—Inline XBRL Taxonomy Label Linkbase Document

Exhibit 101.PRE—Inline XBRL Taxonomy Extension Presentation Linkbase Document

Exhibit 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.

| | | |
|---|---|---|
| | | NorthWestern Corporation |
| Date: July 28, 2021 | By: | /s/ CRYSTAL D. LAIL |
| | | Crystal D. Lail |
| | | *Vice President and Chief Financial Officer* |
| | | *Duly Authorized Officer and Principal Financial Officer* |