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 September 30, 2020

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 Energy

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

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, 50,581,973 shares outstanding at October 16, 2020

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 outbreak of the novel coronavirus (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.

ITEM 1. FINANCIAL STATEMENTS (UNAUDITED)

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Revenues				
Electric	$ 244,155	$ 241,237	$ 706,718	$ 733,933
Gas	36,455	33,599	178,507	195,842
Total Revenues	280,610	274,836	885,225	929,775
Operating Expenses				
Cost of sales	68,038	64,227	220,353	235,706
Operating, general and administrative	73,322	76,998	224,042	238,916
Property and other taxes	45,306	44,089	136,786	133,188
Depreciation and depletion	44,289	43,166	134,336	129,766
Total Operating Expenses	230,955	228,480	715,517	737,576
Operating Income	49,655	46,356	169,708	192,199
Interest Expense, net	(23,677)	(23,722)	(72,298)	(71,023)
Other Income (Expense), net	785	(409)	(973)	864
Income Before Income Taxes	26,763	22,225	96,437	122,040
Income Tax Benefit (Expense)	2,703	(555)	5,227	20,098
Net Income	$ 29,466	$ 21,670	$ 101,664	$ 142,138
Average Common Shares Outstanding	50,577	50,444	50,551	50,422
Basic Earnings per Average Common Share	$ 0.58	$ 0.43	$ 2.01	$ 2.82
Diluted Earnings per Average Common Share	$ 0.58	$ 0.42	$ 2.01	$ 2.80
Dividends Declared per Common Share	$ 0.60	$ 0.575	$ 1.80	$ 1.725

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Net Income	$ 29,466	$ 21,670	$ 101,664	$ 142,138
Other comprehensive income, net of tax:				
Foreign currency translation adjustment	(3)	42	90	18
Reclassification of net losses on derivative instruments	113	114	339	339
Total Other Comprehensive Income	110	156	429	357
Comprehensive Income	$ 29,576	$ 21,826	$ 102,093	$ 142,495

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(in thousands, except share data)

	September 30, 2020	December 31, 2019
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,512	$ 5,145
Restricted cash	10,497	6,925
Accounts receivable, net	133,115	167,405
Inventories	69,055	53,925
Regulatory assets	47,060	54,432
Other	18,089	13,895
Total current assets	**281,328**	**301,727**
Property, plant, and equipment, net	4,860,759	4,700,924
Goodwill	357,586	357,586
Regulatory assets	511,459	484,131
Other noncurrent assets	64,507	66,334
Total Assets	**$ 6,075,639**	**$ 5,910,702**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of finance leases	$ 2,618	$ 2,476
Short term borrowings	100,000	—
Accounts payable	74,663	96,690
Accrued expenses	269,722	202,021
Regulatory liabilities	46,513	33,080
Total current liabilities	**493,516**	**334,267**
Long-term finance leases	15,463	17,439
Long-term debt	2,188,901	2,233,281
Deferred income taxes	456,735	447,986
Noncurrent regulatory liabilities	468,350	451,483
Other noncurrent liabilities	398,124	387,152
Total Liabilities	**4,021,089**	**3,871,608**
Commitments and Contingencies (Note 10)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 54,144,775 and 50,581,098 shares, respectively; Preferred stock, par value 0.01; authorized 50,000,000 shares; none issued	541	541
Treasury stock at cost	(98,242)	(96,015)
Paid-in capital	1,514,820	1,508,970
Retained earnings	646,650	635,246
Accumulated other comprehensive loss	(9,219)	(9,648)
Total Shareholders' Equity	**2,054,550**	**2,039,094**
Total Liabilities and Shareholders' Equity	**$ 6,075,639**	**$ 5,910,702**

See Notes to Condensed Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(in thousands)

	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
OPERATING ACTIVITIES:		
Net income	$ 101,664	$ 142,138
Items not affecting cash:		
Depreciation and depletion	134,336	129,766
Amortization of debt issuance costs, discount and deferred hedge gain	3,604	3,482
Stock-based compensation costs	5,347	4,778
Equity portion of allowance for funds used during construction	(4,503)	(4,118)
Gain on disposition of assets	(26)	(176)
Deferred income taxes	(3,759)	(16,350)
Changes in current assets and liabilities:		
Accounts receivable	34,290	36,000
Inventories	(15,130)	(4,353)
Other current assets	(4,194)	(3,332)
Accounts payable	(4,181)	(13,942)
Accrued expenses	67,553	24,945
Regulatory assets	7,372	(17,662)
Regulatory liabilities	13,433	(19,265)
Other noncurrent assets	(6,225)	(5,366)
Other noncurrent liabilities	(7,066)	(2,684)
Cash Provided by Operating Activities	**322,515**	**253,861**
INVESTING ACTIVITIES:		
Property, plant, and equipment additions	(282,987)	(242,874)
Investment in equity securities	(42)	—
Cash Used in Investing Activities	**(283,029)**	**(242,874)**
FINANCING ACTIVITIES:		
Treasury stock activity	(1,723)	1,220
Dividends on common stock	(90,260)	(86,343)
Issuance of long-term debt	150,000	150,000
Line of credit repayments, net	(193,000)	(76,000)
Issuance of short-term borrowings	100,000	—
Financing costs	(2,564)	(1,074)
Cash Used in Financing Activities	**(37,547)**	**(12,197)**
Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	1,939	(1,210)
Cash, Cash Equivalents, and Restricted Cash, beginning of period	12,070	15,311
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 14,009**	**$ 14,101**
Supplemental Cash Flow Information:		
Cash paid during the period for:		
Income taxes	$ 100	$ 68
Interest	55,220	55,515
Significant non-cash transactions:		
Capital expenditures included in accounts payable	15,986	15,508

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 September 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 June 30, 2019	**53,996**	**3,553**	**$ 540**	**$ (96,178)**	**$1,504,290**	**$611,159**	**$ (9,733)**	**$ 2,010,078**
Net income	—	—	—	—	—	21,670	—	21,670
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	42	42
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	114	114
Stock-based compensation	—	—	—	—	1,169	—	—	1,169
Issuance of shares	—	(3)	—	86	146	—	—	232
Dividends on common stock ($0.575 per share)	—	—	—	—	—	(28,781)	—	(28,781)
Balance at September 30, 2019	**53,996**	**3,550**	**$ 540**	**$ (96,092)**	**$1,505,605**	**$604,048**	**$ (9,577)**	**$ 2,004,524**
Balance at June 30, 2020	**54,145**	**3,571**	**$ 541**	**$ (98,438)**	**$1,513,510**	**$647,272**	**$ (9,329)**	**$ 2,053,556**
Net income	—	—	—	—	—	29,466	—	29,466
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	(3)	(3)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	113	113
Stock-based compensation	—	—	—	—	1,140	—	—	1,140
Issuance of shares	—	(7)	—	196	170	—	—	366
Dividends on common stock ($0.600 per share)	—	—	—	—	—	(30,088)	—	(30,088)
Balance at September 30, 2020	**54,145**	**3,564**	**$ 541**	**$ (98,242)**	**$1,514,820**	**$646,650**	**$ (9,219)**	**$ 2,054,550**

	Nine Months Ended September 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, 2018	**53,889**	**3,566**	**$ 539**	**$ (95,546)**	**$ 1,499,070**	**$ 548,253**	**$ (9,934)**	**$ 1,942,382**
Net income	—	—	—	—	—	142,138	—	142,138
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	18	18
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	339	339
Stock-based compensation	107	25	—	(1,646)	4,744	—	—	3,098
Issuance of shares	—	(41)	1	1,100	1,791	—	—	2,892
Dividends on common stock ($1.725 per share)	—	—	—	—	—	(86,343)	—	(86,343)
Balance at September 30, 2019	**53,996**	**3,550**	**$ 540**	**$ (96,092)**	**$ 1,505,605**	**$ 604,048**	**$ (9,577)**	**$ 2,004,524**
Balance at December 31, 2019	**53,999**	**3,547**	**$ 541**	**$ (96,015)**	**$ 1,508,970**	**$ 635,246**	**$ (9,648)**	**$ 2,039,094**
Net income	—	—	—	—	—	101,664	—	101,664
Foreign currency translation adjustment, net of tax	—	—	—	—	—	—	90	90
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	339	339
Stock-based compensation	146	35	—	(2,740)	5,310	—	—	2,570
Issuance of shares	—	(18)	—	513	540	—	—	1,053
Dividends on common stock ($1.80 per share)	—	—	—	—	—	(90,260)	—	(90,260)
Balance at September 30, 2020	**54,145**	**3,564**	**$ 541**	**$ (98,242)**	**$ 1,514,820**	**$ 646,650**	**$ (9,219)**	**$ 2,054,550**

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 734,800 customers in Montana, South Dakota and Nebraska.

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 September 30, 2020, 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, 2019.

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 September 30, 2020 our estimated remaining gross contractual payments aggregate approximately $123.9 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):

	September 30, 2020	December 31, 2019	September 30, 2019	December 31, 2018
Cash and cash equivalents	$ 3,512	$ 5,145	$ 5,046	$ 7,860
Restricted cash	10,497	6,925	9,055	7,451
Total cash, cash equivalents, and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$ 14,009	$ 12,070	$ 14,101	$ 15,311

Goodwill

We completed our annual goodwill impairment test as of April 1, 2020 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

COVID-19 Accounting Order Filings

In the second and third quarters of 2020, we experienced lower revenues and an increase in certain operating expenses as a result of the COVID-19 pandemic. In March we voluntarily informed both our retail customers and state regulators that disconnections for non-payment would be temporarily suspended. During August we advised customers that we would resume the disconnection process for customers whose accounts are in arrears.

South Dakota - On May 1, 2020, we submitted a joint filing with four other investor owned utilities to the South Dakota Public Utilities Commission (SDPUC) seeking approval for an accounting order to defer certain costs related to the COVID-19 pandemic as a regulatory asset, subject to future review for recovery from customers. We limited our specific request to uncollectible accounts expense in excess of amounts included in the latest electric and natural gas test periods. In August, the SDPUC issued an order granting deferral of our excess uncollectible accounts expense. As of September 30, 2020 we have deferred $0.4 million of uncollectible accounts expense into a regulatory asset in the Condensed Consolidated Balance Sheet.

Montana - On May 29, 2020, we filed a petition for an accounting order with the Montana Public Service Commission (MPSC) seeking approval of an accounting order to (i) defer uncollectible accounts expense in excess of amounts included in the latest electric and natural gas test periods; and (ii) requesting approval of a proposed pension contribution up to $40 million in 2020 to be recognized over a five-year period. The MPSC held a work session in October 2020 voting to allow tracking of uncollectible accounts expense and amortization of incremental pension contributions. We expect a final order on our request during the fourth quarter of 2020, and cannot determine the impact, if any, of the MPSC's decision until a final order is issued.

Pension costs in Montana are included in expense on a pay as you go (cash funding) basis. We contributed $10.2 million to the Montana pension plan during the nine months ended September 30, 2020. We have not yet determined whether we will contribute incremental amounts during the fourth quarter of 2020.

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. The revenue requirement associated with our Montana FERC assets is reflected in our Montana MPSC-jurisdictional rates as a credit to retail customers. We will submit a compliance filing with the MPSC upon resolution of our Montana FERC case adjusting the proposed credit in our Montana retail rates. In June 2019, the FERC issued an order accepting our filing, granting interim rates (subject to refund) effective July 1, 2019, establishing settlement procedures and terminating our related Tax Cuts and Jobs Act filing. A settlement judge was appointed and settlement negotiations are ongoing.

Cost Recovery Mechanisms - Montana

Montana Electric and Natural Gas Supply Cost Trackers - Each year we submit electric and natural gas tracker filings for recovery of supply costs for the 12-month period ended June 30. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our supply procurement activities were prudent.

The MPSC approved a new design for our electric tracker effective July 1, 2017. The revised electric tracker, or Power Costs and Credits Adjustment Mechanism (PCCAM), established a baseline of power supply costs and tracks the differences between the actual costs and associated base rate revenues. Rates are adjusted annually for variances between actual costs and associated revenues with the variances allocated 90% to customers and 10% to shareholders. The initial design of the PCCAM also included a "deadband" which required us to absorb the variances within +/- $4.1 million from the base revenues. In 2019, the Montana legislature made two statutory changes which affected the PCCAM by prohibiting a deadband and allowing 100% recovery of QF purchases. The 90%/10% sharing ratio for other costs remains in place.

In September 2019, we submitted our annual PCCAM filing for the period July 1, 2018 to June 30, 2019, requesting recovery of approximately $23.8 million in electric supply costs. The Montana Consumer Counsel (MCC) and the Montana Environmental Information Center (MEIC) submitted testimony advocating for a disallowance of approximately $6.0 million of replacement power costs incurred during a 2018 third quarter intermittent outage at our Colstrip generating facility necessary to ensure compliance with air permit limits. In addition, the MCC advocated for an application of the deadband and QF cost sharing from July 2018 to the May 2019 statutory change, which would result in an additional under recovery of costs of approximately $4.0 million. The MPSC held a hearing on this matter in June 2020 and we expect a decision in the fourth quarter of 2020. We began collecting costs for the July 2018 - June 2019 tracker period on October 1, 2019, and as of September 30, 2020, the remaining under collection of approximately $2.1 million was reflected in regulatory assets in the Condensed Consolidated Balance Sheets.

Montana QF Power Purchase Cases

Under the Public Utility Regulatory Policies Act (PURPA), electric utilities are required, with certain exceptions, to purchase energy and capacity from independent power producers that are QFs. We track the costs of these purchases through our PCCAM. These purchases are also the subject of proceedings before the MPSC, whose orders are subject to judicial review by Montana state courts.

In May 2016, we filed our biennial update of standard rates for small QFs (3 MW or less). In November 2017, the MPSC approved new, lower rates, reduced the maximum contract term from 25 to 15 years, and ordered that it would apply the same 15-year contract term to our future owned and contracted electric supply resources (Symmetry Finding). We sought judicial review with the Montana State District Court (District Court) of the Symmetry Finding. Cypress Creek Renewables, LLC, Vote Solar, and MEIC, sought judicial review with the District Court of the rates and contract term.

The District Court reversed and modified the MPSC's decisions on rates, contract term, and the Symmetry Finding. We appealed the District Court's order regarding rates and contract term to the Montana Supreme Court, which also granted our request to stay the District Court's decision. The MPSC did not appeal the District Court's Symmetry Finding. On August 24, 2020, the Montana Supreme Court found that the MPSC's order on rates and contract length was arbitrary, left the stay in place, and remanded to the MPSC for consideration when setting rates and contract lengths for small QF's in future regulatory proceedings.

The MPSC adopted the Symmetry Finding in another order when setting the rates and contract term for a large QF - MT Sun, LLC (MTSun). We, as well as MTSun, sought judicial review of the MPSC's order. The District Court reversed and modified the MPSC's order regarding rates, contract length, and the Symmetry Finding. We appealed the District Court's order to the Montana Supreme Court on the issues of rates and contract length, and the MPSC did not appeal the District Court's reversal of the Symmetry Finding. On September 22, 2020, the Montana Supreme Court found the MPSC's order on rates and contract length was arbitrary and that MTSun is entitled to the rates and contract term determined by the District Court. We are authorized through our PCCAM tariff to recover 100% of our QF purchased power costs.

Montana Community Renewable Energy Projects (CREPs)

We were required to acquire, as of December 31, 2019, approximately 66 MW of CREPs. While we have made progress towards meeting this obligation by acquiring approximately 36 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. We expect to file waiver requests for 2017, 2018, and 2019 after resolution of that litigation. If the Montana Supreme Court rules that the 2015 and 2016 waivers were invalid or if the requested waivers for 2017 through 2019 are not granted, we are likely to be liable for penalties. If the MPSC imposes a penalty, the amount of the penalty would depend on how the MPSC calculated the energy that a CREP would have produced. However, we do not believe any such penalty 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 September 30,			
	2020		2019	
Income Before Income Taxes	$ 26,763		$ 22,225	
Income tax calculated at federal statutory rate	5,621	21.0 %	4,667	21.0 %
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	46	0.2	65	0.3
Flow-through repairs deductions	(4,213)	(15.7)	(2,606)	(11.7)
Production tax credits	(2,205)	(8.2)	(1,414)	(6.3)
Amortization of excess deferred income tax	(222)	(0.8)	(374)	(1.7)
Plant and depreciation of flow-through items	103	0.4	(263)	(1.2)
Prior year permanent return to accrual adjustments	(1,728)	(6.5)	559	2.5
Other, net	(105)	(0.5)	(79)	(0.4)
	(8,324)	(31.1)	(4,112)	(18.5)
Income tax (benefit) expense	$ (2,703)	(10.1)%	$ 555	2.5 %

	Nine Months Ended September 30,			
	2020		2019	
Income Before Income Taxes	$ 96,437		$ 122,040	
Income tax calculated at federal statutory rate	20,252	21.0 %	25,628	21.0 %
Permanent or flow through adjustments:				
State income, net of federal provisions	73	0.1	1,230	1.0
Flow-through repairs deductions	(14,859)	(15.4)	(12,694)	(10.4)
Production tax credits	(7,553)	(7.8)	(7,252)	(5.9)
Share-based compensation	(609)	(0.6)	186	0.2
Amortization of excess deferred income tax	(731)	(0.8)	(1,939)	(1.6)
Prior year permanent return to accrual adjustments	(1,728)	(1.8)	559	0.4
Plant and depreciation of flow through items	299	0.3	(2,449)	(2.0)
Recognition of unrecognized tax benefit	—	—	(22,825)	(18.7)
Other, net	(371)	(0.4)	(542)	(0.5)
	(25,479)	(26.4)	(45,726)	(37.5)
Income tax benefit	$ (5,227)	(5.4)%	$ (20,098)	(16.5)%

The income tax benefit for 2019 reflects the recognition of approximately $22.8 million of unrecognized tax benefits, including approximately $2.7 million of accrued interest and penalties, net of tax, due to the lapse of statutes of limitation in the second quarter of 2019.

Coronavirus Aid, Relief, and Economic Security Act (the CARES Act)

In response to the COVID-19 pandemic, on March 27, 2020, President Donald Trump signed into law the CARES Act. We evaluated the provisions of the CARES Act as of September 30, 2020, and determined it had no material effect on our Financial Statements. Certain tax provisions may result in immaterial cash refunds.

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 have unrecognized tax benefits of approximately $33.9 million as of September 30, 2020, including approximately $28.0 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 September 30, 2020, we do not have any amounts accrued for the payment of interest and penalties. As discussed above, during the nine months ended September 30, 2019, we released $2.7 million of accrued interest in the Condensed Consolidated Statements of Income.

Tax years 2016 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 2002 forward.

(4) Comprehensive Income (Loss)

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

	Three Months Ended					
	September 30, 2020			September 30, 2019		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (3)	$ —	$ (3)	$ 42	$ —	$ 42
Reclassification of net income (loss) on derivative instruments	153	(40)	113	154	(40)	114
Other comprehensive income (loss)	$ 150	$ (40)	$ 110	$ 196	$ (40)	$ 156

	Nine Months Ended					
	September 30, 2020			September 30, 2019		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 90	$ —	$ 90	$ 18	$ —	$ 18
Reclassification of net income (loss) on derivative instruments	459	(120)	339	460	(121)	339
Other comprehensive income (loss)	$ 549	$ (120)	$ 429	$ 478	$ (121)	$ 357

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

	September 30, 2020	December 31, 2019
Foreign currency translation	$ 1,503	$ 1,413
Derivative instruments designated as cash flow hedges	(10,842)	(11,181)
Postretirement medical plans	120	120
Accumulated other comprehensive loss	$ (9,219)	$ (9,648)

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

		Three Months Ended September 30, 2020			
	Affected Line Item in the Condensed Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,955)	$ 120	$ 1,506	$ (9,329)
Other comprehensive income before reclassifications		—	—	(3)	(3)
Amounts reclassified from AOCL	Interest Expense	113	—	—	113
Net current-period other comprehensive income (loss)		113	—	(3)	110
Ending balance		$ (10,842)	$ 120	$ 1,503	$ (9,219)

	Affected Line Item in the Condensed Consolidated Statements of Income	Three Months Ended September 30, 2019 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (11,408)	$ 251	$ 1,424	$ (9,733)
Other comprehensive income before reclassifications				42	42
Amounts reclassified from AOCL	Interest Expense	114			114
Net current-period other comprehensive income		114	—	42	156
Ending balance		$ (11,294)	$ 251	$ 1,466	$ (9,577)

	Affected Line Item in the Condensed Consolidated Statements of Income	Nine Months Ended September 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		—	—	90	90
Amounts reclassified from AOCL	Interest Expense	339	—	—	339
Net current-period other comprehensive income		339	—	90	429
Ending balance		$ (10,842)	$ 120	$ 1,503	$ (9,219)

	Affected Line Item in the Condensed Consolidated Statements of Income	Nine Months Ended September 30, 2019 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Pension and Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (11,633)	$ 251	$ 1,448	$ (9,934)
Other comprehensive income before reclassifications		—	—	18	18
Amounts reclassified from AOCL	Interest Expense	339	—	—	339
Net current-period other comprehensive income		339	—	18	357
Ending balance		$ (11,294)	$ 251	$ 1,466	$ (9,577)

(5) Financing Activities

In April 2020, we entered into a $100 million Term Loan Agreement (Term Loan) and borrowed the full amount. The Term Loan bears interest at variable rates tied to the Eurodollar rate plus a credit spread of 1.50%. Proceeds were used to repay a portion of our outstanding revolving credit facility borrowings and for general corporate purposes. All principal and unpaid interest under the Term Loan is due and payable on April 2, 2021. The Term Loan provides for prepayment of the principal and interest; however, amounts prepaid may not be reborrowed. The Term Loan requires us to maintain a consolidated indebtedness to total capitalization ratio of 65 percent or less. It also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Term Loan; however a default on the Term Loan would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

In May 2020, we issued $100 million principal amount of Montana First Mortgage Bonds and $50 million principal amount of South Dakota First Mortgage Bonds, each at a fixed interest rate of 3.21% maturing on May 15, 2030. These bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana and South Dakota.

On September 2, 2020, we entered into a new $425 million Credit Agreement (Credit Facility) to replace our existing facility. The Credit Facility increases the capacity from that of the prior facility by $25 million to $425 million and extended the maturity date to September 2, 2023 (from December 12, 2021), with 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 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 13% of the total availability.

The Credit Facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Credit Facility; however a default on the Credit Facility would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

(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 September 30, 2020	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 244,155	$ 36,455	$ —	$ —	$ 280,610
Cost of sales	61,155	6,883	—	—	68,038
Gross margin	183,000	29,572	—	—	212,572
Operating, general and administrative	54,367	20,059	(1,104)	—	73,322
Property and other taxes	35,532	9,772	2	—	45,306
Depreciation and depletion	36,670	7,619	—	—	44,289
Operating income (loss)	56,431	(7,878)	1,102	—	49,655
Interest expense, net	(21,286)	(1,574)	(817)	—	(23,677)
Other income (expense), net	1,559	459	(1,233)	—	785
Income tax benefit	1,197	607	899	—	2,703
Net income (loss)	$ 37,901	$ (8,386)	$ (49)	$ —	$ 29,466
Total assets	$ 4,430,279	$ 1,634,606	$ 10,754	$ —	$ 6,075,639
Capital expenditures	$ 87,432	$ 19,073	$ —	$ —	$ 106,505

Three Months Ended September 30, 2019	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 241,237	$ 33,599	$ —	$ —	$ 274,836
Cost of sales	58,768	5,459	—	—	64,227
Gross margin	182,469	28,140	—	—	210,609
Operating, general and administrative	57,433	18,830	735	—	76,998
Property and other taxes	34,731	9,355	3	—	44,089
Depreciation and depletion	35,824	7,342	—	—	43,166
Operating income (loss)	54,481	(7,387)	(738)	—	46,356
Interest expense, net	(19,481)	(1,588)	(2,653)	—	(23,722)
Other (expense) income, net	(677)	(344)	612	—	(409)
Income tax (expense) benefit	(1,415)	(232)	1,092	—	(555)
Net income (loss)	$ 32,908	$ (9,551)	$ (1,687)	$ —	$ 21,670
Total assets	$ 4,632,077	$ 1,173,513	$ 4,590	$ —	$ 5,810,180
Capital expenditures	$ 70,063	$ 25,784	$ —	$ —	$ 95,847

Nine Months Ended September 30, 2020	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 706,718	$ 178,507	$ —	$ —	$ 885,225
Cost of sales	173,294	47,059	—	—	220,353
Gross margin	533,424	131,448	—	—	664,872
Operating, general and administrative	166,854	61,348	(4,160)	—	224,042
Property and other taxes	107,079	29,700	7	—	136,786
Depreciation and depletion	110,692	23,644	—	—	134,336
Operating income	148,799	16,756	4,153	—	169,708
Interest expense, net	(63,585)	(4,824)	(3,889)	—	(72,298)
Other income (expense)	3,131	863	(4,967)	—	(973)
Income tax benefit (expense)	2,609	(467)	3,085	—	5,227
Net income (loss)	$ 90,954	$ 12,328	$ (1,618)	$ —	$ 101,664
Total assets	$ 4,430,279	$ 1,634,606	$ 10,754	$ —	$ 6,075,639
Capital expenditures	$ 230,524	$ 52,463	$ —	$ —	$ 282,987

Nine Months Ended September 30, 2019	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 733,933	$ 195,842	$ —	$ —	$ 929,775
Cost of sales	178,423	57,283	—	—	235,706
Gross margin	555,510	138,559	—	—	694,069
Operating, general and administrative	174,544	60,803	3,569	—	238,916
Property and other taxes	104,612	28,569	7	—	133,188
Depreciation and depletion	107,595	22,171	—	—	129,766
Operating income (loss)	168,759	27,016	(3,576)	—	192,199
Interest expense, net	(58,301)	(4,599)	(8,123)	—	(71,023)
Other (expense) income	(1,458)	(874)	3,196	—	864
Income tax (expense) benefit	(4,937)	493	24,542	—	20,098
Net income	$ 104,063	$ 22,036	$ 16,039	$ —	$ 142,138
Total assets	$ 4,632,077	$ 1,173,513	$ 4,590	$ —	$ 5,810,180
Capital expenditures	$ 186,155	$ 56,719	$ —	$ —	$ 242,874

(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					
	September 30, 2020			September 30, 2019		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 78.5	$ 9.9	$ 88.4	$ 68.4	$ 8.9	$ 77.3
South Dakota	18.9	1.7	20.6	16.0	1.7	17.7
Nebraska	—	1.7	1.7	—	1.8	1.8
Residential	**97.4**	**13.3**	**110.7**	**84.4**	**12.4**	**96.8**
Montana	89.1	5.6	94.7	87.7	5.5	93.2
South Dakota	27.4	1.0	28.4	26.3	1.3	27.6
Nebraska	—	0.7	0.7	—	0.9	0.9
Commercial	**116.5**	**7.3**	**123.8**	**114.0**	**7.7**	**121.7**
Industrial	9.2	0.1	9.3	10.6	0.1	10.7
Lighting, Governmental, Irrigation, and Interdepartmental	11.9	0.1	12.0	12.4	0.1	12.5
Total Customer Revenues	**235.0**	**20.8**	**255.8**	**221.4**	**20.3**	**241.7**
Other Tariff and Contract Based Revenues	14.9	8.3	23.2	15.3	7.7	23.0
Total Revenue from Contracts with Customers	**249.9**	**29.1**	**279.0**	**236.7**	**28.0**	**264.7**
Regulatory amortization	(5.7)	7.4	1.7	4.5	5.6	10.1
Total Revenues	**$ 244.2**	**$ 36.5**	**$ 280.7**	**$ 241.2**	**$ 33.6**	**$ 274.8**

	Nine Months Ended					
	September 30, 2020			September 30, 2019		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Montana	$ 237.7	$ 65.7	$ 303.4	$ 225.4	$ 73.3	$ 298.7
South Dakota	52.4	16.7	69.1	47.4	20.4	67.8
Nebraska	—	12.9	12.9	—	15.7	15.7
Residential	**290.1**	**95.3**	**385.4**	**272.8**	**109.4**	**382.2**
Montana	252.5	33.0	285.5	257.3	38.0	295.3
South Dakota	77.1	11.2	88.3	71.2	14.1	85.3
Nebraska	—	6.2	6.2	—	8.3	8.3
Commercial	**329.6**	**50.4**	**380.0**	**328.5**	**60.4**	**388.9**
Industrial	27.2	0.5	27.7	32.4	0.7	33.1
Lighting, Governmental, Irrigation, and Interdepartmental	26.4	0.7	27.1	25.2	0.6	25.8
Total Customer Revenues	**673.3**	**146.9**	**820.2**	**658.9**	**171.1**	**830.0**
Other Tariff and Contract Based Revenues	44.1	26.5	70.6	46.5	26.6	73.1
Total Revenue from Contracts with Customers	**717.4**	**173.4**	**890.8**	**705.4**	**197.7**	**903.1**
Regulatory amortization	(10.7)	5.1	(5.6)	28.5	(1.9)	26.6
Total Revenues	**$ 706.7**	**$ 178.5**	**$ 885.2**	**$ 733.9**	**$ 195.8**	**$ 929.7**

(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	
	September 30, 2020	September 30, 2019
Basic computation	50,576,564	50,443,866
Dilutive effect of:		
Performance share awards (1)	97,529	335,371
Diluted computation	50,674,093	50,779,237

	Nine Months Ended	
	September 30, 2020	September 30, 2019
Basic computation	50,551,121	50,422,028
Dilutive effect of:		
Performance share awards (1)	105,395	334,002
Diluted computation	50,656,516	50,756,030

(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.

(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 September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 2,779	$ 2,409	$ 93	$ 82
Interest cost	5,710	6,622	123	152
Expected return on plan assets	(6,541)	(6,360)	(246)	(217)
Amortization of prior service cost (credit)	—	1,636	(471)	(471)
Recognized actuarial loss (gain)	1,257	—	(15)	(24)
Plan settlements	—	715	—	—
Net periodic benefit cost (credit)	$ 3,205	$ 5,022	$ (516)	$ (478)

	Pension Benefits		Other Postretirement Benefits	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Components of Net Periodic Benefit Cost (Credit)				
Service cost	$ 8,337	$ 7,228	$ 278	$ 248
Interest cost	17,130	19,866	369	457
Expected return on plan assets	(19,622)	(19,082)	(738)	(652)
Amortization of prior service cost (credit)	—	4,908	(1,412)	(1,412)
Recognized actuarial loss (gain)	3,771	—	(45)	(72)
Plan settlements	—	715	—	—
Net periodic benefit cost (credit)	$ 9,616	$ 13,635	$ (1,548)	$ (1,431)

We contributed $11.4 million to our pension plans during the nine months ended September 30, 2020. As discussed in Note 2 *Regulatory Matters*, we have not yet determined whether we will contribute incremental amounts to the Montana pension plan during the fourth quarter of 2020.

(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 $27.8 million to $30.5 million. As of September 30, 2020, we had a reserve of approximately $28.8 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 $22.6 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 September 30, 2020, the reserve for remediation costs at this site is approximately $7.8 million, and we estimate that approximately $2.4 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 2020 and into 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 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. Various challenges to ACE are pending in the District of Columbia Circuit (D.C. Circuit). Oral arguments in the cases were heard before the D.C. Circuit on October 8, 2020. No decision has been issued in the cases.

Generally, ACE provides more regulatory flexibility to individual states and likely will not reduce CO_2 emissions as much as the CPP. Under the ACE, states must establish unit-specific standards that reflect emissions achievable through heat rate improvements, which the EPA designated as the best system of emissions reduction, and if the state chooses, take into account the remaining useful life of the unit and other source specific factors. States generally have three years to submit the standards to the EPA and coal-fired plants will have two additional years to comply with the standards.

We cannot predict whether or how ACE will be applied to our plants, including 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.

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 issued or proposed. Regarding the ACE, as discussed above, we cannot predict the impact on us until state plans are adopted and any judicial reviews are completed.

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 later in 2020 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, 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.

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 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.

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. The Federal District Court held a scheduling conference on June 18, 2020 at which it approved a plan for discovery, and set deadlines in the case, including a trial date of September 27, 2021 on the issue of navigability. Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable. The parties are engaged in discovery and the State has served its expert reports. We, along with the other Defendants, are scheduled to serve our expert reports in December.

We dispute the State's claims and intend to vigorously defend the lawsuit. This matter is still at its early stages, and 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.

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

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 734,800 customers in Montana, South Dakota and Nebraska. 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, 2019.

We are working to deliver safe, reliable and innovative energy solutions that create value for our 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 by continuing to invest in our system including:

- 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 nine months ended September 30, 2020 and 2019.

HOW WE PERFORMED AGAINST OUR THIRD QUARTER 2019 RESULTS

	Three Months Ended September 30, 2020 vs. 2019		
	Income Before Income Taxes	Income Tax (Expense) Benefit	Net Income
		(in millions)	
Third Quarter 2019	**$ 22.2**	**$ (0.5)**	**$ 21.7**
Items (decreasing) increasing net income:			
Lower operating, general, and administrative expenses impacting net income	3.1	(0.8)	2.3
Higher electric retail volumes and demand	2.4	(0.6)	1.8
Lower Montana natural gas rates	(0.1)	—	(0.1)
Lower Montana electric transmission revenue	(0.3)	0.1	(0.2)
Lower Montana natural gas volumes	(0.3)	0.1	(0.2)
Lower Montana electric supply cost recovery	(0.5)	0.1	(0.4)
Higher depreciation and depletion	(1.1)	0.3	(0.8)
Other	1.4	4.0	5.4
Third Quarter 2020	**$ 26.8**	**$ 2.7**	**$ 29.5**
Change in Net Income			**$ 7.8**

Consolidated net income for the three months ended September 30, 2020 was $29.5 million as compared with $21.7 million for the same period in 2019. This increase was primarily due to higher gross margin, lower operating expenses and lower income taxes, offset in part by higher depreciation and depletion expense.

Following is a brief overview of significant items for 2020.

SIGNIFICANT TRENDS AND REGULATION

COVID-19 Pandemic

We are one of many companies providing essential services during the national emergency related to the COVID-19 pandemic. Our level of service to our 734,800 customers remains uninterrupted. We implemented a comprehensive set of actions to help our customers, communities, and employees, while maintaining our commitments to provide reliable service and to continue to monitor and adapt our financial business plan for the evolving COVID-19 pandemic challenges. In March, we voluntarily informed both our retail customers and state regulators that disconnections for non-payment would be temporarily suspended, and we have provided an incremental $400,000 in charitable contributions and aid to assist the communities we serve. Our CEO made an official declaration of emergency in accordance with our continuity of operations plan and emergency standard operating procedures, implementing an incident command structure that remains in effect. We have taken extra precautions for our employees who work in the field and for employees who continue to work in our facilities. This includes implementation of work from home policies, social-distancing protocols, face-covering directives, and travel restrictions where appropriate. Currently, we do not anticipate any employee layoffs and are continuing to hire for critical positions to maintain our high level of reliability and customer service. We continue to implement strong physical and cyber-security measures to enable our systems to remain functional to serve our operational needs with a remote workforce and to keep our company running to provide high quality service to our customers. In August we advised customers that we would resume the disconnection process for customers whose accounts are in arrears.

In response to the COVID-19 pandemic, President Donald Trump signed into law the CARES Act on March 27, 2020. The CARES Act provides numerous tax provisions and other stimulus measures, including temporary changes regarding the prior and future utilization of net operating losses, temporary changes to the prior and future limitations on interest deductions, temporary suspension of certain payment requirements for the employer portion of Social Security taxes, technical corrections from prior tax legislation for tax depreciation of certain qualified improvement property, and the creation of certain refundable employee retention credits. We evaluated the provisions of the CARES Act and do not anticipate the associated impacts, if any, will have a material effect on our financial position or liquidity.

2020 Outlook - The COVID-19 pandemic has impacted our financial results with lower gross margin driven by a reduction in our commercial and industrial revenue, offset in part by an increase in usage by residential customers. We also experienced an increase in certain operating expenses including an increase in uncollectible accounts and interest expense offset in part by lower operating expenses as detailed below. COVID-19 continues to be an evolving situation and we expect to continue to experience impacts to our financial results in the fourth quarter of 2020.

Estimate of Covid Impacts (millions)

	Three Months Ended June 30, 2020		Three Months Ended September 30, 2020	
	Low	High	Low	High
Gross Margin	($3.0)	($4.0)	($2.0)	($3.0)
Operating expenses				
Medical, labor, and travel & training	(2.8)	(2.8)	(1.2)	(1.2)
Uncollectible Accounts	3.1	3.1	2.4	2.4
Total Operating Expense	0.3	0.3	1.2	1.2
Operating Loss	(3.3)	(4.3)	(3.2)	(4.2)
Interest expense	(0.7)	(0.7)	—	—
Pretax Loss	(4.0)	(5.0)	(3.2)	(4.2)
Income tax benefit	1.0	1.3	0.8	1.1
Net Loss	($3.0)	($3.7)	($2.4)	($3.1)
ETR	25.3%	25.3%	25.3%	25.3%

We submitted accounting order requests in Montana and South Dakota to allow for the deferral of uncollectible accounts expense in excess of amounts currently recovered from customers and to determine ratemaking treatment in a future proceeding.

- The SDPUC issued an order in August 2020, authorizing deferral of costs for possible recovery through future rates. In the third quarter of 2020, we deferred approximately $0.4 million of uncollectible accounts expense in South Dakota.

- The MPSC held a work session in October 2020 and voted to allow tracking of uncollectible accounts expense. We expect a final written order during the fourth quarter of 2020. We cannot determine the impact of the MPSC's decision, if any, until a final order is issued.

We are working with customers who have been unable to pay during the COVID-19 pandemic, including offering extended payment arrangements. In each of our jurisdictions, we resumed disconnection procedures for non-payment during the third quarter of 2020 and expect normal winter disconnection procedures to apply effective November 1st.

While we have not experienced significant supply chain challenges, so far, we continue to closely manage and monitor developments in our supply chain. We remain on track for our approximately $400 million capital investment as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2019. The continued progression of and global response to the COVID-19 pandemic increases the risk of delays in construction activities and equipment deliveries related to our capital projects, including potential delays in obtaining permits from government agencies, resulting in a potential deferral of capital expenditures.

The ongoing impacts of the COVID-19 pandemic remain uncertain. Further extension of the slowdown of the United States' economic growth, demand for commodities and/or material changes in governmental policy may continue to result in lower economic growth with lower demand for electricity and natural gas, as well as the 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.

Liquidity - We continue to maintain adequate liquidity to operate our business and fund our ongoing capital program. As of September 30, 2020, our total net liquidity was approximately $357.5 million, including $3.5 million of cash and $354.0 million of revolving credit facility availability. During the second quarter of 2020, as precautionary measures to increase our cash position and preserve financial flexibility in light of uncertainty in the markets, we accessed the capital markets in two transactions:

- On April 3, 2020, we entered into a $100 million 364-Day Term Loan Credit Agreement (Term Loan), with two of our relationship banks, and borrowed the full amount under the Term Loan. Borrowings from this facility allow us to meet our temporarily increased targeted minimum liquidity threshold of $200 million, up from our long-standing $100 million level; and
- On May 15, 2020, we issued $150 million principal amount 10-year, 3.21% first mortgage bonds.

In addition, on September 2, 2020, we entered into a new $425 million Credit Facility increasing the capacity of our revolving credit facility by $25 million to $425 million and extending the maturity date to September 2, 2023 (from December 12, 2021).

For further discussion of these transactions, see the *Liquidity and Capital Resources* discussion. We expect to issue equity in 2021 to maintain and protect our current credit ratings in balance with our current capital expenditure plans.

Proposed Colstrip Unit 4 Capacity Acquisition

In February 2020, we filed an application with the MPSC for pre-approval to acquire Puget Sound Energy’s (Puget) 25% interest, 185 MW of generation, in Colstrip Unit 4 for one dollar. As part of the application, we sought approval to sell 90 MW of energy to Puget through a Power Purchase Agreement (PPA) for roughly five years at a price indexed to hourly prices at the Mid-Columbia power hub, with a price floor reflecting the recovery of fixed operating and maintenance costs and variable generation costs. Our application includes zero net effect on customer bills and proposes to establish a reserve fund with benefits from the PPA and market purchase savings. If approved, the reserve fund will be used to address environmental compliance, remediation and decommissioning costs associated with our existing 222 MW ownership interest in Colstrip Unit 4. Puget remains responsible for its presale 25% ownership share of all costs for remediation of existing environmental conditions and decommissioning regardless of the proposed acquisition or when Colstrip Unit 4 is retired.

Under the Ownership and Operation Agreement to which each of the Colstrip Units 3 and 4 co-owners are a party, each co-owner has a right of first refusal to purchase Puget’s interest. In April 2020, Talen provided notices of its exercise of its right of first refusal to acquire a proportionate share of Puget's interest in Colstrip Unit 4, which would reduce our proposed transaction to 92.5 MW, and the associated five-year PPA to Puget to 45 MW. We supplemented our application with the MPSC to reflect this development and file the amended the purchase and sale agreement with Puget, reducing the size of the transaction.

A hearing on our application to the MPSC is scheduled for December 2020. We expect a decision from the MPSC in the first quarter of 2021.Should the MPSC decline to grant our application in all material respects, we have the right, under the purchase and sale agreement with Puget to terminate the transaction. Closing the transaction is also contingent upon approval of Puget’s application to the Washington Utilities and Transportation Commission (WUTC). A hearing on Puget’s application before the WUTC is scheduled for November 2020.

Colstrip Transmission System - We also entered into a separate agreement with Puget to acquire an additional 95 MW interest in the 500 kilovolt (kV) Colstrip Transmission System for net book value at the time of the sale. The net book value is expected to range between $2.5 million to $3.8 million. After the roughly 5-year PPA with Puget, we will have the option to acquire another 90 MW interest in the 500 kV Colstrip Transmission System for net book value at that time. These transmission acquisitions are conditioned upon approval and closing of the Colstrip Unit 4 acquisition. Talen, while not a co-owner of the Colstrip Transmission System, has claimed that its right of first refusal as to the Colstrip Unit 4 transaction extends to the separate transmission transaction and initiated arbitration under the Ownership and Operation Agreement. We disagree with Talen’s claim in this regard and have opposed Talen’s efforts to obtain an interest in the Colstrip Transmission System. We expect a decision from the arbitrator in October 2020.

Electric Resource Planning - Montana

We are currently 630 MW short of our peak needs, which we procure in the market. 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 February 2020 for up to 280 MWs of peaking and flexible capacity to be available for commercial operation in early 2023. We expect to repeat the process in subsequent years to provide a resource-adequate energy and capacity portfolio by 2025.

Initial bids from the February 2020, 280 MW competitive solicitation were submitted in July 2020. Engineering, procurement and construction bids were submitted on our behalf for generating facilities providing long-duration flexible capacity in excess of 200 MWs. The bids are under evaluation by an independent party, and we expect the successful project(s) to be selected and announced by the first quarter of 2021.

If the transaction with Puget for additional capacity discussed above is approved and we acquire 92.5 MW from Puget, we expect the transaction to reduce our need for capacity in future competitive solicitations by 85 MW based on resource adequacy requirements.

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.

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 Revenues less Cost of Sales as presented 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.

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 September 30, 2020 Compared with the Three Months Ended September 30, 2019

Consolidated net income for the three months ended September 30, 2020 was $29.5 million as compared with $21.7 million for the same period in 2019. This increase was primarily due to higher gross margin, lower operating, general and administrative expenses and lower income taxes, offset in part by higher depreciation and depletion.

Consolidated operating revenues for the three months ended September 30, 2020 were $280.7 million as compared with $274.8 million for the same period in 2019. Consolidated gross margin for the three months ended September 30, 2020 was $212.6 million as compared with $210.6 million for the same period in 2019, an increase of $2.0 million.

	Electric		Natural Gas		Total	
	2020	2019	2020	2019	2020	2019
	(dollars in millions)					
Reconciliation of operating revenue to gross margin:						
Operating Revenues	$ 244.2	$ 241.2	$ 36.5	$ 33.6	$ 280.7	$ 274.8
Cost of Sales	61.2	58.7	6.9	5.5	68.1	64.2
Gross Margin(1)	**$ 183.0**	**$ 182.5**	**$ 29.6**	**$ 28.1**	**$ 212.6**	**$ 210.6**

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

	Three Months Ended September 30,			
	2020	2019	Change	% Change
	(dollars in millions)			
Gross Margin				
Electric	$ 183.0	$ 182.5	$ 0.5	0.3 %
Natural Gas	29.6	28.1	1.5	5.3
Total Gross Margin(1)	**$ 212.6**	**$ 210.6**	**$ 2.0**	**0.9 %**

(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 2020 vs. 2019
Gross Margin Items Impacting Net Income	
Electric retail volumes and demand	$ 2.4
Montana electric supply cost recovery	(0.5)
Electric transmission	(0.3)
Natural gas retail volumes	(0.3)
Montana natural gas rates	(0.1)
Other	1.7
Change in Gross Margin Impacting Net Income	**2.9**
Gross Margin Items Offset Within Net Income	
Property tax revenue offset in property tax expense	1.1
Operating expenses recovered in revenue, offset in operating expense	(1.0)
Production tax credits reducing revenue, offset in income tax expense	(1.0)
Change in Gross Margin Items Offset Within Net Income	**(0.9)**
Increase in Consolidated Gross Margin(1)	**$ 2.0**

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

Consolidated gross margin increased $2.0 million, including a $2.9 million increase from items impacting net income and a $0.9 million decrease from items offset within net income.

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

- An increase in electric retail volumes and demand driven by warmer weather and customer growth, partly offset by lower industrial demand unrelated to the COVID-19 pandemic. Impacts of the COVID-19 pandemic offset this improvement by approximately $2 - $3 million driven by lower commercial and industrial demand, partly offset by a slight increase in residential usage.
- Higher Montana electric supply costs as compared with the prior period;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing, including the closure of Colstrip units 1 and 2;

- Lower natural gas commercial and industrial loads as a result of reduced demand, offset in part by customer growth; and
- A decrease in Montana natural gas rates associated with the annual step down for our Montana gas production assets.

	Three Months Ended September 30,			
	2020	2019	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 73.3	$ 77.0	$ (3.7)	(4.8)%
Property and other taxes	45.3	44.1	1.2	2.7
Depreciation and depletion	44.3	43.2	1.1	2.5
	$ 162.9	**$ 164.3**	**$ (1.4)**	**(0.9)%**

Consolidated operating, general and administrative expenses were $73.3 million for the three months ended September 30, 2020, as compared with $77.0 million for the three months ended September 30, 2019. Primary components of the change include the following (in millions):

	Operating, General & Administrative Expenses 2020 vs. 2019
Operating, General & Administrative Expenses Impacting Net Income	
Employee benefits	$ (2.0)
Hazard trees	(1.3)
Labor	(1.2)
Generation maintenance	(0.9)
Travel and training	(0.8)
Uncollectible accounts	2.4
Other	0.7
Change in Items Impacting Net Income	**(3.1)**
Operating, General & Administrative Expenses Offset Within Net Income	
Pension and other postretirement benefits, offset in other income	2.4
Operating expenses recovered in trackers, offset in revenue	(1.1)
Non-employee directors deferred compensation, offset in other income	(1.9)
Change in Operating, General & Administrative Expense Items Offset Within Net Income	**(0.6)**
Decrease in Operating, General & Administrative Expenses	**$ (3.7)**

Consolidated operating, general and administrative expenses decreased $3.7 million, including a $3.1 million decrease from items impacting net income and a $0.6 million decrease from items offset within net income.

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

- Lower employee benefit costs primarily due to a decrease in employee incentive compensation expense;
- Lower hazard tree line clearance costs. As previously disclosed, we finalized our plan to address hazard tree clearance in 2018 and accelerated the program in 2019. We expect costs in 2020 to reflect a normal level, which is lower than 2019;
- Decreased labor costs including approximately $0.4 million of in-home customer work which was limited by the COVID-19 pandemic and more time being spent by employees on capital projects than maintenance projects (which are expensed);
- Lower maintenance costs at our electric generation facilities;

- A reduction in travel and training costs due to the impacts of the COVID-19 pandemic; and
- Increased uncollectible accounts. In March 2020, we voluntarily suspended service disconnections for non-payment, to help customers who may be financially impacted by the COVID-19 pandemic. We resumed standard disconnection processes in all of our operating jurisdictions during the third quarter. As a result of the South Dakota accounting order, we deferred approximately $0.4 million of uncollectible accounts expense during the third quarter of 2020.

Property and other taxes were $45.3 million for the three months ended September 30, 2020, as compared with $44.1 million in the same period of 2019. This increase was due primarily to an increase in Montana state and local taxes offset in part by lower MPSC tax and invasive species tax. 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 $44.3 million for the three months ended September 30, 2020, as compared with $43.2 million in the same period of 2019. This increase was primarily due to plant additions.

Consolidated operating income for the three months ended September 30, 2020 was $49.7 million as compared with $46.4 million in the same period of 2019. This increase was primarily due to the increase in gross margin and lower operating expenses, offset in part by higher property tax and depreciation expense.

Consolidated interest expense remained flat for the three months ended September 30, 2020 as compared with the same period of 2019. Borrowings during the second and third quarter of 2020 were primarily utilized to repay balances on our revolver, increasing our liquidity and preserving financial flexibility in light of recent uncertainty in the markets. This was offset by lower interest on our revolving credit facilities.

Consolidated other income was $0.8 million for the three months ended September 30, 2020 as compared to consolidated other expense of $0.4 million during the same period of 2019. This change includes a decrease in other pension expense of $2.4 million, partially offset by a $1.8 million decrease in the value of deferred shares held in trust for non-employee directors deferred compensation (both of which are offset in operating, general, and administrative expense with no impact to net income), and higher capitalization of Allowance for Funds Used During Construction (AFUDC).

Consolidated income tax benefit for the three months ended September 30, 2020 was $2.7 million as compared with income tax expense of $0.6 million in the same period of 2019. Our effective tax rate for the three months ended September 30, 2020 was (10.1)% as compared with 2.5% for the same period in 2019. We expect our effective tax rate to range between (5)% to 0% in 2020.

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

	Three Months Ended September 30,			
	2020		2019	
Income Before Income Taxes	$ 26.8		$ 22.2	
Income tax calculated at federal statutory rate	5.6	21.0 %	4.7	21.0 %
Permanent or flow-through adjustments:				
State income tax, net of federal provisions	—	0.2	0.1	0.3
Flow-through repairs deductions	(4.2)	(15.7)	(2.6)	(11.7)
Production tax credits	(2.2)	(8.2)	(1.4)	(6.3)
Prior year permanent return to accrual adjustments	(1.7)	(6.5)	0.6	2.5
Amortization of excess deferred income tax	(0.2)	(0.8)	(0.4)	(1.7)
Plant and depreciation of flow-through items	0.1	0.4	(0.3)	(1.2)
Other, net	(0.1)	(0.5)	(0.1)	(0.4)
	(8.3)	(31.1)	(4.1)	(18.5)
Income tax (benefit) expense	$ (2.7)	(10.1)%	$ 0.6	2.5 %

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.

Nine Months Ended September 30, 2020 Compared with the Nine Months Ended September 30, 2019

Consolidated net income for the nine months ended September 30, 2020 was $101.7 million as compared with $142.1 million for the same period in 2019. This decrease was primarily due to an income tax benefit in 2019, lower gross margin in 2020 due to warmer winter weather and impacts of the COVID-19 pandemic and higher depreciation expense, offset in part by a decrease in operating, general and administrative expenses.

Consolidated operating revenues for the nine months ended September 30, 2020 were $885.2 million as compared with $929.8 million for the same period in 2019. This decrease was primarily due to lower volumes from warmer winter weather and impacts of the COVID-19 pandemic, partly offset by customer growth. Consolidated gross margin for the nine months ended September 30, 2020 was $664.8 million as compared with $694.1 million for the same period in 2019, a decrease of $29.3 million.

	Electric		Natural Gas		Total	
	2020	2019	2020	2019	2020	2019
	(dollars in millions)					
Reconciliation of operating revenue to gross margin:						
Operating Revenues	$ 706.7	$ 733.9	$ 178.5	$ 195.9	$ 885.2	$ 929.8
Cost of Sales	173.3	178.4	47.1	57.3	220.4	235.7
Gross Margin[(1)]	**$ 533.4**	**$ 555.5**	**$ 131.4**	**$ 138.6**	**$ 664.8**	**$ 694.1**

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

	Nine Months Ended September 30,			
	2020	2019	Change	% Change
	(dollars in millions)			
Gross Margin				
Electric	$ 533.4	$ 555.5	$ (22.1)	(4.0) %
Natural Gas	131.4	138.6	(7.2)	(5.2)
Total Gross Margin[(1)]	**$ 664.8**	**$ 694.1**	**$ (29.3)**	**(4.2)%**

(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 2020 vs. 2019
Gross Margin Items Impacting Net Income	
Natural gas retail volumes	$ (8.3)
Electric retail volumes and demand	(6.5)
Lower electric QF liability adjustment	(3.3)
Montana electric supply cost recovery	(3.2)
Electric transmission	(1.8)
Montana natural gas rates	(0.8)
Montana electric retail rates	1.6
Other	(5.3)
Change in Gross Margin Impacting Net Income	**(27.6)**
Gross Margin Items Offset Within Net Income	
Production tax credits reducing revenue, offset in income tax expense	(4.0)
Operating expenses recovered in revenue, offset in operating expense	(1.2)
Property tax revenue, offset in property tax expense	3.5
Change in Items Offset Within Net Income	**(1.7)**
Decrease in Consolidated Gross Margin[(1)]	**$ (29.3)**

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

Consolidated gross margin decreased $29.3 million, including a $27.6 million decrease from items impacting net income and a $1.7 million decrease from items offset within net income.

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

- A decrease in gas volumes due primarily to warmer winter weather and lower customer usage, offset in part by customer growth;
- A decrease in electric retail volumes due to warmer winter weather in Montana and lower industrial demand unrelated to the COVID-19 pandemic, partly offset by customer growth and warmer summer weather. In addition, impacts of the COVID-19 pandemic drove a decline of approximately $5 - $7 million as a result of lower commercial and industrial demand, partly offset by higher residential usage;
- A less favorable adjustment of our electric QF liability (unrecoverable costs associated with PURPA contracts as a part of a 2002 stipulation with the MPSC and other parties) as compared with the same period in 2019 due to the combination of:
    - A net $1.1 million lower favorable adjustment due to actual price escalation, which was less than estimated ($2.2 million in the current period as compared with $3.3 million in the prior period); and
    - Higher costs of approximately $2.2 million, due to a $0.9 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $3.1 million reduction in costs in the prior period.
- A prior year recovery of Montana electric supply costs as a result of changes in the associated statute, offset in part by lower supply costs in 2020;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing, including the closure of Colstrip units 1 and 2;
- A decrease in Montana natural gas rates associated with the annual step down for our Montana gas production assets;
- An increase in Montana electric retail rates; and
- A decrease in other due primarily to nonrecurring items.

	Nine Months Ended September 30,			
	2020	2019	Change	% Change
	(dollars in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 224.0	$ 238.9	$ (14.9)	(6.2) %
Property and other taxes	136.8	133.2	3.6	2.7
Depreciation and depletion	134.3	129.8	4.5	3.5
	$ 495.1	**$ 501.9**	**$ (6.8)**	**(1.4)%**

Consolidated operating, general and administrative expenses were $224.0 million for the nine months ended September 30, 2020, as compared with $238.9 million for the nine months ended September 30, 2019. Primary components of the change include the following (in millions):

	Operating, General & Administrative Expenses 2020 vs. 2019
Operating, General & Administrative Expenses Impacting Net Income	
Employee benefits	$ (5.7)
Labor	(3.0)
Hazard trees	(2.5)
Generation maintenance	(2.1)
Travel and training	(2.0)
Uncollectible accounts	5.5
Other	(1.2)
Change in Items Impacting Net Income	**(11.0)**
Operating, General & Administrative Expenses Offset Within Net Income	
Non-employee directors deferred compensation, offset in other income	(8.2)
Operating expenses recovered in trackers, offset in revenue	(1.3)
Pension and other postretirement benefits, offset in other income	5.6
Change in Operating, General & Administrative Expense Items Offset Within Net Income	**(3.9)**
Decrease in Operating, General & Administrative Expenses	**$ (14.9)**

Consolidated operating, general and administrative expenses decreased $14.9 million, including an $11.0 million decrease from items impacting net income and a $3.9 million decrease from items offset within net income.

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

- Lower employee benefit costs primarily due to a decrease in medical expense and employee incentive compensation expense. Medical costs includes approximately $0.9 million of reductions due to the COVID-19 pandemic;
- Decreased labor costs including approximately $1.1 million of in home customer work limited due to the COVID-19 pandemic during the second and third quarters of 2020 and more time being spent by employees on capital projects than maintenance projects (which are expensed);
- Lower hazard tree line clearance costs. As previously disclosed, we finalized our plan to address hazard tree clearance in 2018 and accelerated the program in 2019. We expect costs in 2020 to reflect a normal level, which is lower than 2019;
- Lower maintenance at our electric generation facilities;
- A reduction in employee travel and training costs due to the impacts of the COVID-19 pandemic; and
- Increased uncollectible accounts. In March 2020, we voluntarily suspended service disconnections for non-payment, to help customers who may be financially impacted by the COVID-19 pandemic. We resumed standard disconnection processes in all of our operating jurisdictions during the third quarter. As a result of the South Dakota accounting order, we deferred approximately $0.4 million of uncollectible accounts expense during the third quarter of 2020.

Property and other taxes were $136.8 million for the nine months ended September 30, 2020, as compared with $133.2 million in the same period of 2019. This increase was primarily due to plant additions and higher estimated property valuations in Montana.

Depreciation and depletion expense was $134.3 million for the nine months ended September 30, 2020, as compared with $129.8 million in the same period of 2019. This increase was primarily due to plant additions.

Consolidated operating income for the nine months ended September 30, 2020 was $169.7 million as compared with $192.2 million in the same period of 2019. This decrease was primarily due to lower gross margin, partly offset by lower operating expenses and higher property and other taxes and depreciation expense.

Consolidated interest expense for the nine months ended September 30, 2020 was $72.3 million as compared with $71.0 million in the same period of 2019, reflecting borrowings issued as a precautionary measure in order to increase our cash position and preserve financial flexibility in light of the uncertainty in the markets, partly offset by lower interest on our revolving credit facilities.

Consolidated other expense was $1.0 million for the nine months ended September 30, 2020 as compared to other income of $0.9 million during the same period of 2019. This was primarily due to a $8.2 million decrease in the value of deferred shares held in trust for non-employee directors deferred compensation that was partly offset by a $5.6 million decrease in other pension expense (both of which are offset in operating, general, and administrative expense with no impact to net income), and higher capitalization of AFUDC.

Consolidated income tax benefit for the nine months ended September 30, 2020 was $5.2 million as compared with $20.1 million in the same period of 2019. The income tax benefit for 2019 reflects the recognition of approximately $22.8 million of unrecognized tax benefits, including approximately $2.7 million of accrued interest and penalties, due to the lapse of statutes of limitation in the second quarter of 2019. Our effective tax rate for the nine months ended September 30, 2020 was (5.4)% as compared with (16.5)% for the same period of 2019. We expect our effective tax rate to range between (5)% to 0% in 2020.

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

	Nine Months Ended September 30,			
	2020		2019	
Income Before Income Taxes	$ 96.4		$ 122.0	
Income tax calculated at federal statutory rate	20.3	21.0 %	25.6	21.0 %
Permanent or flow-through adjustments:				
State income, net of federal provisions	0.1	0.1	1.2	1.0
Flow-through repairs deductions	(14.9)	(15.4)	(12.7)	(10.4)
Production tax credits	(7.6)	(7.8)	(7.3)	(5.9)
Prior year permanent return to accrual adjustments	(1.7)	(1.8)	0.6	0.4
Amortization of excess deferred income taxes	(0.7)	(0.8)	(1.9)	(1.6)
Share-based compensation	(0.6)	(0.6)	0.2	0.2
Recognition of unrecognized tax benefit	—	—	(22.8)	(18.7)
Plant and depreciation of flow-through items	0.3	0.3	(2.5)	(2.0)
Other, net	(0.4)	(0.4)	(0.5)	(0.5)
	(25.5)	(26.4)	(45.7)	(37.5)
Income tax benefit	$ (5.2)	(5.4)%	$ (20.1)	(16.5)%

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.

ELECTRIC SEGMENT

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

- Retail: Sales of electricity to residential, commercial and industrial customers.
- 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.
- 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 September 30, 2020 Compared with the Three Months Ended September 30, 2019

	Results			
	2020	2019	Change	% Change
	(dollars in millions)			
Retail revenues	$ 235.0	$ 221.4	$ 13.6	6.1 %
Regulatory amortization	(5.5)	4.6	(10.1)	(219.6)
Total retail revenues	229.5	226.0	3.5	1.5
Transmission	12.9	13.3	(0.4)	(3.0)
Wholesale and Other	1.8	1.9	(0.1)	(5.3)
Total Revenues	**244.2**	**241.2**	**3.0**	**1.2**
Total Cost of Sales	**61.2**	**58.7**	**2.5**	**4.3**
Gross Margin(1)	**$ 183.0**	**$ 182.5**	**$ 0.5**	**0.3 %**

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

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2020	2019	2020	2019	2020	2019
	(in thousands)					
Montana	$ 78,549	$ 68,469	633	569	307,892	303,263
South Dakota	18,912	15,987	160	141	50,584	50,596
Residential	**97,461**	**84,456**	**793**	**710**	**358,476**	**353,859**
Montana	89,082	87,754	794	807	70,320	69,217
South Dakota	27,373	26,295	284	291	12,870	12,873
Commercial	**116,455**	**114,049**	**1,078**	**1,098**	**83,190**	**82,090**
Industrial	9,212	10,523	621	766	78	78
Other	11,910	12,324	86	90	8,193	8,140
Total Retail Electric	**$ 235,038**	**$ 221,352**	**2,578**	**2,664**	**449,937**	**444,167**

	Cooling Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	340	332	351	2% warmer	3% cooler
South Dakota	755	606	639	25% warmer	18% warmer

	Heating Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	255	319	276	20% warmer	8% warmer
South Dakota	71	37	86	De minimis	De minimis

The following summarizes the components of the changes in electric gross margin for the three months ended September 30, 2020 and 2019 (in millions):

	Gross Margin 2020 vs. 2019
Gross Margin Items Impacting Net Income	
Retail volumes and demand	$ 2.4
Montana electric supply cost recovery	(0.5)
Transmission	(0.3)
Other	—
Change in Gross Margin Impacting Net Income	1.6
Gross Margin Items Offset Within Net Income	
Operating expenses recovered in revenue, offset in operating expense	(1.0)
Production tax credits reducing revenue, offset in income tax expense	(1.0)
Property tax revenue, offset in property tax expense	0.9
Change in Gross Margin Items Offset Within Net Income	(1.1)
Increase in Gross Margin(1)	**$ 0.5**

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

Gross margin increased $0.5 million, including a $1.6 million increase from items impacting net income and a $1.1 million decrease from items offset within net income.

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

- An increase in electric retail volumes and demand driven by warmer weather and customer growth, partly offset by lower industrial demand unrelated to the COVID-19 pandemic. Impacts of the COVID-19 pandemic offset this improvment by approximately $2 - $3 million driven by lower commercial and industrial demand, partly offset by a slight increase in residential usage.
- Higher Montana electric supply costs as compared with the prior period; and
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing, including the closure of Colstrip units 1 and 2.

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.

Nine Months Ended September 30, 2020 Compared with the Nine Months Ended September 30, 2019

	Results			
	2020	2019	Change	% Change
	(dollars in millions)			
Retail revenues	$ 673.3	$ 658.9	$ 14.4	2.2 %
Regulatory amortization	(9.3)	30.0	(39.3)	(131.0)
Total retail revenues	664.0	688.9	(24.9)	(3.6)
Transmission	38.4	40.2	(1.8)	(4.5)
Wholesale and Other	4.3	4.8	(0.5)	(10.4)
Total Revenues	**706.7**	**733.9**	**(27.2)**	**(3.7)**
Total Cost of Sales	**173.3**	**178.4**	**(5.1)**	**(2.9)**
Gross Margin[(1)]	**$ 533.4**	**$ 555.5**	**$ (22.1)**	**(4.0)%**

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

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2020	2019	2020	2019	2020	2019
	(in thousands)					
Montana	$ 237,777	$ 225,392	1,944	1,898	306,886	302,687
South Dakota	52,427	47,444	463	459	50,629	50,606
Residential	**290,204**	**272,836**	**2,407**	**2,357**	**357,515**	**353,293**
Montana	252,514	257,284	2,269	2,380	69,949	68,723
South Dakota	77,057	71,218	818	828	12,812	12,822
Commercial	**329,571**	**328,502**	**3,087**	**3,208**	**82,761**	**81,545**
Industrial	27,162	32,368	2,026	2,192	78	78
Other	26,400	25,228	157	150	6,467	6,336
Total Retail Electric	**$ 673,337**	**$ 658,934**	**7,677**	**7,907**	**446,821**	**441,252**

	Cooling Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	395	370	403	7% warmer	2% cooler
South Dakota	844	660	699	28% warmer	21% warmer

	Heating Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	4,610	5,540	4,654	17% warmer	1% warmer
South Dakota	5,564	6,350	5,686	12% warmer	2% warmer

The following summarizes the components of the changes in electric gross margin for the nine months ended September 30, 2020 and 2019 (in millions):

		Gross Margin 2020 vs. 2019
Gross Margin Items Impacting Net Income		
Retail volumes and demand	$	(6.5)
QF liability adjustment		(3.3)
Montana supply cost recovery		(3.2)
Transmission		(1.8)
Montana retail rates		1.6
Other		(7.0)
Change in Gross Margin Impacting Net Income		(20.2)
Gross Margin Items Offset Within Net Income		
Production tax credits reducing revenue, offset in income tax expense		(4.0)
Operating expenses recovered in revenue, offset in operating expense		(1.2)
Property tax revenue, offset in property tax expense		3.3
Change in Items Offset Within Net Income		(1.9)
Decrease in Gross Margin[(1)]	**$**	**(22.1)**

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

Gross margin decreased $22.1 million, including a $20.2 million decrease from items impacting net income and a $1.9 million decrease from items offset within net income.

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

- A decrease in volumes due to warmer winter weather in Montana and lower industrial demand unrelated to the COVID-19 pandemic, partly offset by customer growth and warmer summer weather. In addition, impacts of the COVID-19 pandemic drove a decline of approximately $5 - $7 million, as a result of lower commercial and industrial demand, partly offset by higher residential usage;
- A less favorable adjustment of our electric QF liability (unrecoverable costs associated with PURPA contracts as a part of a 2002 stipulation with the MPSC and other parties) as compared with the same period in 2019 due to the combination of:
    - A net $1.1 million lower favorable adjustment due to actual price escalation, which was less than estimated ($2.2 million in the current period as compared with $3.3 million in the prior period); and
    - Higher costs of approximately $2.2 million, due to a $0.9 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $3.1 million reduction in costs in the prior period.
- A prior year recovery of Montana electric supply costs as a result of changes in the associated statute, offset in part by lower supply costs in 2020;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing, including the closure of Colstrip units 1 and 2;
- An increase in Montana electric rates; and
- A decrease in other due primarily to nonrecurring items.

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.
- 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.
- Wholesale: Primarily represents transportation and storage for others.

Three Months Ended September 30, 2020 Compared with the Three Months Ended September 30, 2019

	Results			
	2020	2019	Change	% Change
	(dollars in millions)			
Retail revenues	$ 20.8	$ 20.3	$ 0.5	2.5 %
Regulatory amortization	7.3	5.4	1.9	35.2
Total retail revenues	28.1	25.7	2.4	9.3
Wholesale and other	8.4	7.9	0.5	6.3
Total Revenues	**36.5**	**33.6**	**2.9**	**8.6**
Total Cost of Sales	**6.9**	**5.5**	**1.4**	**25.5**
Gross Margin[(1)]	**$ 29.6**	**$ 28.1**	**$ 1.5**	**5.3 %**

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

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2020	2019	2020	2019	2020	2019
	(in thousands)					
Montana	$ 9,896	$ 8,909	956	945	177,410	174,550
South Dakota	1,702	1,676	114	112	40,437	39,795
Nebraska	1,698	1,833	156	141	37,467	37,173
Residential	**13,296**	**12,418**	**1,226**	**1,198**	**255,314**	**251,518**
Montana	5,598	5,490	611	675	24,412	24,094
South Dakota	1,030	1,283	170	216	6,864	6,740
Nebraska	684	900	143	156	4,945	4,872
Commercial	**7,312**	**7,673**	**924**	**1,047**	**36,221**	**35,706**
Industrial	51	79	6	11	231	239
Other	92	97	12	14	153	166
Total Retail Gas	**$ 20,751**	**$ 20,267**	**2,168**	**2,270**	**291,919**	**287,629**

	Heating Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	306	353	336	13% warmer	9% warmer
South Dakota	71	37	86	De minimis	De minimis
Nebraska	40	17	46	De minimis	De minimis

The following summarizes the components of the changes in natural gas gross margin for the three months ended September 30, 2020 and 2019:

	Gross Margin 2020 vs. 2019 (in millions)	
Gross Margin Items Impacting Net Income		
Retail volumes	$	(0.3)
Montana rates		(0.1)
Other		1.7
Change in Gross Margin Impacting Net Income		1.3
Gross Margin Items Offset Within Net Income		
Property tax revenue, offset in property tax expense		0.2
Change in Gross Margin Items Offset Within Net Income		0.2
Increase in Gross Margin[(1)]	**$**	**1.5**

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

Gross margin increased $1.5 million, including a $1.3 million increase for items impacting net income and a $0.2 million increase from items offset within net income.

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

- Lower commercial and industrial loads as a result of reduced demand, offset in part 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.

Nine Months Ended September 30, 2020 Compared with the Nine Months Ended September 30, 2019

	Results			
	2020	2019	Change	% Change
	(dollars in millions)			
Retail revenues	$ 146.9	$ 171.1	$ (24.2)	(14.1)%
Regulatory amortization	5.0	(1.7)	6.7	(394.1)
Total retail revenues	151.9	169.4	(17.5)	(10.3)
Wholesale and other	26.6	26.5	0.1	0.4
Total Revenues	**178.5**	**195.9**	**(17.4)**	**(8.9)**
Total Cost of Sales	**47.1**	**57.3**	**(10.2)**	**(17.8)**
Gross Margin(1)	**$ 131.4**	**$ 138.6**	**$ (7.2)**	**(5.2)%**

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

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2020	2019	2020	2019	2020	2019
	(in thousands)					
Montana	$ 65,674	$ 73,295	8,937	10,025	177,036	174,555
South Dakota	16,697	20,376	2,310	2,545	40,509	40,019
Nebraska	12,908	15,678	1,984	2,181	37,542	37,373
Residential	**95,279**	**109,349**	**13,231**	**14,751**	**255,087**	**251,947**
Montana	32,988	37,987	4,674	5,458	24,455	24,171
South Dakota	11,213	14,074	2,360	2,481	6,889	6,789
Nebraska	6,284	8,294	1,394	1,612	4,973	4,894
Commercial	**50,485**	**60,355**	**8,428**	**9,551**	**36,317**	**35,854**
Industrial	503	672	75	101	231	240
Other	612	746	104	124	152	166
Total Retail Gas	**$ 146,879**	**$ 171,122**	**21,838**	**24,527**	**291,787**	**288,207**

	Heating Degree Days			2020 as compared with:	
	2020	2019	Historic Average	2019	Historic Average
Montana	4,707	5,604	4,863	16% warmer	3% warmer
South Dakota	5,564	6,350	5,686	12% warmer	2% warmer
Nebraska	4,250	4,866	4,678	13% warmer	9% warmer

The following summarizes the components of the changes in natural gas gross margin for the nine months ended September 30, 2020 and 2019:

	Gross Margin 2020 vs. 2019
	(in millions)
Gross Margin Items Impacting Net Income	
Retail volumes	$ (8.3)
Montana rates	(0.8)
Other	1.7
Change in Gross Margin Impacting Net Income	(7.4)
Gross Margin Items Offset Within Net Income	
Property tax revenue, offset in property tax expense	0.2
Change in Items Offset Within Net Income	0.2
Decrease in Gross Margin[(1)]	**$ (7.2)**

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

Gross margin decreased $7.2 million, including a $7.4 million decrease from items impacting net income and a $0.2 million increase from items offset within net income.

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

- A decrease in gas volumes due primarily to warmer winter weather and lower customer usage, offset in part by customer growth; and
- A reduction of rates due to 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, existing borrowing capacity, and issuance of debt securities should be 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 and the receipt of cash from operations. In addition, a material change in operations 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.

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 plan to maintain a 50 - 55 percent debt to total capital ratio excluding finance leases, and expect to continue to target a long-term dividend payout ratio of 60 - 70 percent of earnings per share; however, there can be no assurance that we will be able to meet these targets.

As discussed above in the *Significant Trends and Regulation* section of Management's Discussion and Analysis, in response to the COVID-19 pandemic and as a precautionary measure in order to increase our cash position and preserve financial flexibility in light of current uncertainty in the markets, we entered into a $100 million Term Loan. On April 3, 2020, we borrowed the full amount under the Term Loan. We used the proceeds to pay down a portion of our outstanding revolving credit facility borrowings and for general corporate purposes. The Term Loan bears interest at variable rates tied to the Eurodollar rate plus a credit spread of 1.50%. All principal and unpaid interest under the Term Loan is due and payable on April 2, 2021. The Term Loan provides for prepayment of the principal and interest; however, amounts prepaid may not be reborrowed. The Term Loan requires us to maintain a consolidated indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and to accelerate the maturity of all amounts outstanding under the Term Loan. As of October 16, 2020, we were in compliance with this covenant.

In May 2020, we issued $100 million principal amount of Montana First Mortgage Bonds and $50 million principal amount of South Dakota First Mortgage Bonds, each at a fixed interest rate of 3.21% maturing on May 15, 2030. We issued these bonds in a transaction exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana and South Dakota.

On September 2, 2020, we entered into a new $425 million Credit Facility to replace our current facility. The Credit Facility increased the capacity from that of the prior facility by $25 million to $425 million and extended the maturity date to September 2, 2023 (from December 12, 2021), with 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 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% of the total availability.

Liquidity is provided by internal cash flows and the use of our credit facilities. This includes the $425 million Credit Facility, a $25 million revolving credit facility to provide swingline borrowing capability, and the $100 million Term Loan discussed above. We utilize availability under our revolving 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 September 30, 2020, our total net liquidity was approximately $357.5 million, including $3.5 million of cash and $354.0 million of revolving credit facility availability. As of September 30, 2020, there were no letters of credit outstanding and $96.0 million in outstanding borrowings under our revolving credit facilities. Availability under our revolving credit facilities was $376.0 million as of October 16, 2020.

We remain on track for our approximately $400 million capital investment as disclosed in our annual report on Form 10-K for the year ended December 31, 2019. We continue to monitor the disruption in capital markets caused by the COVID-19 pandemic. If conditions further deteriorate and we need to access the capital markets there can be no assurance that we will be able to obtain such financing on commercially reasonable terms or at all. We expect to issue equity in 2021 to maintain and protect our current credit ratings in balance with our current capital expenditure plans.

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.

The effect of this seasonality on our liquidity is also impacted by changes in electric and natural gas market prices. 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.

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.

As of September 30, 2020, we have under collected our costs recovered through tracking mechanisms by approximately $8.1 million. We under collected our costs by approximately $32.5 million as of December 31, 2019 and under collected our costs by approximately $28.2 million as of September 30, 2019.

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 October 16, 2020, our current ratings with these agencies are as follows:

	Senior Secured Rating	Senior Unsecured Rating	Commercial Paper	Outlook
Fitch	A	A-	F2	Negative
Moody’s	A3	Baa2	Prime-2	Stable
S&P	A-	BBB	A-2	Stable

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):

	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating Activities		
Net income	$ 101.7	$ 142.1
Non-cash adjustments to net income	135.0	117.4
Changes in working capital	99.1	2.4
Other noncurrent assets and liabilities	(13.3)	(8.0)
Cash Provided by Operating Activities	**322.5**	**253.9**
Investing Activities		
Property, plant and equipment additions	(283.0)	(242.9)
Cash Used in Investing Activities	**(283.0)**	**(242.9)**
Financing Activities		
Issuance of long-term debt	150.0	150.0
Issuance of short-term borrowings	100.0	—
Line of credit repayments, net	(193.0)	(76.0)
Dividends on common stock	(90.3)	(86.3)
Financing costs	(2.6)	(1.1)
Other	(1.7)	1.2
Cash Used in Financing Activities	**(37.6)**	**(12.2)**
Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	**1.9**	**(1.2)**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	12.1	15.3
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 14.0**	**$ 14.1**

Cash Provided by Operating Activities

As of September 30, 2020, cash, cash equivalents, and restricted cash were $14.0 million as compared with $12.1 million at December 31, 2019 and $14.1 million at September 30, 2019. Cash provided by operating activities totaled $322.5 million for the nine months ended September 30, 2020 as compared with $253.9 million during the nine months ended September 30, 2019. This increase in operating cash flows is primarily due to improved collections of energy supply costs in the current period, as compared with higher procured supply costs, and payments reducing cash flows in 2019 including credits to Montana customers of approximately $20.5 million and transmission generation interconnection refunds. These improvements were offset in part by reduced net income.

Cash Used in Investing Activities

Cash used in investing activities increased by approximately $40.1 million as compared with the first nine months of 2019. Plant additions during the first nine months of 2020 include maintenance additions of approximately $192.4 million and capacity related capital expenditures of $90.6 million. Plant additions during the first nine months of 2019 included maintenance additions of approximately $177.1 million, and capacity related capital expenditures of approximately $65.8 million.

Cash Used in Financing Activities

Cash used in financing activities totaled $37.6 million during the nine months ended September 30, 2020 as compared with $12.2 million during the nine months ended September 30, 2019. During the nine months ended September 30, 2020, cash used in financing activities reflects net repayments under our revolving lines of credit of $193.0 million and dividends of $90.3 million, offset in part by proceeds from the issuance of debt of $150.0 million and short-term borrowings of $100.0 million. During the nine months ended September 30, 2019, net cash used in financing activities reflects payment of dividends of $86.3

million and net borrowings under our revolving lines of credit of $76.0 million, offset in part by proceeds from the issuance of debt of $150.0 million.

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 September 30, 2020. See our Annual Report on Form 10-K for the year ended December 31, 2019 for additional discussion.

	Total	2020	2021	2022	2023	2024	Thereafter
				(in thousands)			
Long-term debt (1)	$ 2,202,637	$ —	$ —	$ —	$ 240,660	$ —	$ 1,961,977
Finance leases	18,082	642	2,668	2,875	3,098	3,338	5,461
Short-term borrowings	100,000	—	100,000	—	—	—	—
Estimated pension and other postretirement obligations (2)	55,959	3,386	13,491	13,209	13,097	12,776	NA
Qualifying facilities liability (3)	571,011	19,055	77,722	79,572	81,646	79,384	233,632
Supply and capacity contracts (4)	1,808,019	55,897	169,277	150,265	150,776	145,560	1,136,244
Contractual interest payments on debt (5)	1,481,855	21,415	85,367	82,417	81,212	79,524	1,131,920
Environmental remediation obligations (6)	3,880	1,822	912	720	213	213	NA
Total Commitments (7)	$ 6,241,443	$ 102,217	$ 449,437	$ 329,058	$ 570,702	$ 320,795	$ 4,469,234

(1) Represents cash payments for long-term debt and excludes $13.7 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 $63 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $571.0 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $463.5 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 24 years.
(5) Contractual interest payments includes our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 1.39% on the outstanding balance through maturity of the facilities.
(6) We estimate environmental remediation obligations for five years, as it is not practicable to estimate thereafter. Our environmental reserve relates primarily to the remediation of former manufactured gas plant sites owned by us.
(7) Potential tax payments related to uncertain tax positions are not practicable to estimate and have been excluded from this table.

Other Obligations - As a co-owner of Colstrip, we provided surety bonds of approximately $22.8 million and $13.2 million as of September 30, 2020 and December 31, 2019, 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, 2019. As of September 30, 2020, 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.

Interest Rate Risk

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. We manage our interest rate risk by issuing primarily fixed-rate long-term debt with varying maturities, refinancing certain debt and, at times, hedging the interest rate on anticipated borrowings. All of our debt has fixed interest rates, with the exception of our revolving credit facilities and Term Loan. The $425 million Credit Facility bears interest at 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. In addition, we have a $25 million revolving credit facility, to provide swingline borrowing capability. The $25 million revolving credit facility bears interest at the lower of prime plus a credit spread of 0.13%, or available rates tied to the Eurodollar rate plus a credit spread of 0.65%. As of September 30, 2020, we had approximately $96.0 million in borrowings under our revolving credit facilities. A 1.0% increase in interest rates would increase our annual interest expense by approximately $1.0 million.

In addition, in April 2020, we entered into a 364-day Term Loan and borrowed the full amount of $100 million, which bears interest at variable rates tied to the Eurodollar rate plus a credit spread of 1.50%. A 1.0% increase in interest rates would increase interest expense by approximately $1.0 million.

Commodity Price Risk

We are exposed to commodity price risk due to our reliance on market purchases to fulfill a portion of our electric and natural gas supply requirements. We also participate in the wholesale electric market to balance our supply of power from our own generating resources. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

As part of our overall strategy for fulfilling our electric and natural gas supply requirements, we employ the use of market purchases and sales, including forward contracts. These types of contracts are included in our supply portfolios and in some instances, are used to manage price volatility risk by taking advantage of seasonal fluctuations in market prices. These contracts are part of an overall portfolio approach intended to provide price stability for consumers. As a regulated utility, our exposure to market risk caused by changes in commodity prices is mitigated because these commodity costs are included in our Montana, South Dakota and Nebraska cost tracking mechanisms and, are recoverable from customers subject to a regulatory review for prudency and, in the case of our Montana PCCAM, a sharing mechanism.

Counterparty Credit Risk

We are exposed to counterparty credit risk related to the ability of these counterparties to meet their contractual payment obligations, and the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. If counterparties seek financial protection under bankruptcy laws, we are exposed to greater financial risks. We are also exposed to counterparty credit risk related to providing transmission service to our customers under our Open Access Transmission Tariff and under gas transportation agreements. We have risk management policies in place to limit our transactions to high quality counterparties. We monitor closely the status of our counterparties and take action, as appropriate, to further manage this risk. This includes, but is not limited to, requiring letters of credit or prepayment terms. There can be no assurance, however, that the management tools we employ will eliminate the risk of loss.

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 are 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.

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 negatively impacted our operations, liquidity, financial condition and results of operations since March 2020. The situation remains dynamic and subject to rapid and possibly material change, which ultimately could result in material negative effects on our business and results of operations.

Economic - The COVID-19 pandemic continues to be an evolving situation with an extended disruption of economic activity. We have experienced lower demand for electricity and natural gas as well as the inability of various customers, contractors, suppliers and other business partners to fulfill their obligations. There can be no assurance that any decrease in revenues resulting from the COVID-19 pandemic will return to previous levels in the future. 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 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 we cannot predict the ultimate impact of the COVID-19 pandemic, our financial results in the second and third quarters were impacted by lower sales volumes, increased operating expenses due primarily to an increase in reserves for uncollectible accounts and an increase in interest expense. 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.

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 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.

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, cyber-attacks, 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 or travel or government restrictions 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 all of the above-described 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. Although we provide critical infrastructure services and are permitted to continue to operate in each of our jurisdictions, including jurisdictions that have mandated the closure of certain businesses, there is no assurance that we will be allowed to continue full operations under future government orders or restrictions.

Any such workforce implications, 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 exacerbate risks discussed below, any of which could have a material effect on us. This situation is changing rapidly and additional impacts may arise that we are not aware of currently.

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. Our PCCAM docket for the July 1, 2018 to June 30, 2019 time period includes replacement power costs procured during an intermittent outage at Colstrip Unit 4 in 2018. In addition, in May 2019, the statute changed removing the previously established “deadband” of +/- $4.1 million from base costs and removing QF costs from the 90% / 10% sharing calculation. The MPSC held a hearing in this docket in June 2020 and we expect a decision during the fourth quarter of 2020. There can be no assurance that the MPSC will allow recovery of costs consistent with our filing, 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 pressure pushing down 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.

In May 2019, we submitted a rate filing with the FERC related to our Montana transmission assets. The revenue collected from FERC-jurisdictional customers associated with our Montana FERC assets is reflected in our Montana MPSC-jurisdictional rates as a credit to retail customers. Settlement negotiations with the Intervenors are ongoing. If the FERC determines our request is not supported and/or decreases overall electric rates, or the MPSC-jurisdictional electric rates are not updated consistent with the FERC decision, it could have a material adverse effect on our operating and financial results.

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. Congress may implement new federal laws 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 environmental laws and regulations, including legislative and regulatory responses to climate change, with which compliance may be difficult and costly.

We are subject to extensive laws and regulations imposed by federal, state, and local government authorities in the ordinary course of operations with regard to public policy on climate change, the environment, including environmental laws and regulations relating to air and water quality, protection of natural resources, migratory birds and other wildlife, solid waste disposal, coal ash and other environmental considerations. We are also subject to new interpretations of those laws and regulations. We believe that we are in compliance with environmental regulatory requirements; however, possible future developments, such as more stringent environmental laws and regulations, the timing of future enforcement proceedings that may be taken by environmental authorities, and judicial opinions 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.

On June 19, 2019, EPA finalized the Affordable Clean Energy Rule (ACE). ACE repealed the 2015 Clean Power Plan (CPP) in regulating greenhouse gas (GHG) emissions from coal-fired plants. Under ACE, states must establish unit-specific standards. Although the United States has not adopted federal GHG legislation, as GHG 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.

Many of these environmental laws and regulations 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 damages 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.

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.

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 58% carbon-free, it includes coal-fired resources and environmental advocacy groups, certain investors and other third parties oppose the operation of certain facilities, expressing concerns about the environmental and climate-related impacts from fossil fuels. These efforts may increase in scope and frequency depending on a number of variables, including the course of Federal and State environmental regulation and the financial resources devoted to these opposition activities. These risks include litigation originated by third parties 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. We are obligated to pay for the costs of closure of our share of generation facilities, including our share of the costs of reclamation of some of the mines that supply coal to the coal-fired power plants. Likewise, other owners or participants are responsible for their shares of the decommissioning and reclamation obligations. 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 these 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. Costs of facilities in common with all four units are 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.

In addition, the remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Our recovery of costs associated with the shut-down of the facility prior to the end of the depreciable life would be subject to MPSC approval. Two of the other joint owners have entered into settlements with regulators to accelerate the recovery of their investment in Colstrip Units 3 and 4 by using a depreciable life through 2027. 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. The owners, which had earlier set and requested a depreciable life through 2027, are subject to this Washington statute and its 2025 deadline. On July 20, 2020, a third joint owner filed a Settlement Stipulation with the Washington Utilities and Transportation Commission, agreeing to a depreciable life of Unit 4 through 2023. Under the Ownership and Operation Agreement to which each of the Colstrip Units 3 and 4 co-owners are a party, we believe that Units 3 and 4 cannot be closed without each co-owner’s consent.

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 (CIP) 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 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.

For our electric distribution and transmission system, hazard trees located inside or outside our lines' rights of way pose risks. 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 beetle infestations have caused a significant increase in the quantity of standing dead and dying timber, increasing the risk that such trees may fall from either inside or outside our right-of-way into a power line igniting a fire. 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.

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. 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. None of these attempts has individually or in aggregate resulted in a security incident with a material impact on our financial condition or results of operations. 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 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 also increase the threat of fires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, fires 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 creating high energy demand on our own and/or other systems 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 reliably 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, approximately 46% 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. This could result in an inability to physically deliver electricity to our customers. In addition, the suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us.

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% 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 development of the Western Energy Imbalance Market and our expected participation, 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 — Credit Agreement, dated September 2, 2020, among NorthWestern Corporation, as borrower; the several banks and other financial institutions or entities from time to time parties to the agreement, as lenders; BofA Securities, Inc., Credit Suisse Securities (USA) LLC, and U.S. Bank National Association as joint lead arrangers; Credit Suisse Securities (USA) LLC, and U.S. Bank National Association as co-syndication agents; Keybank National Association as documentation agent; and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated September 4, 2020, Commission File No. 1-10499).

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: October 22, 2020	By: /s/ BRIAN B. BIRD
	Brian B. Bird
	Chief Financial Officer
	Duly Authorized Officer and Principal Financial Officer