UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

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 CORPORATION

(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)	(Name of each exchange on which registered)
Common Stock, $0.01 par value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
None

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

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

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

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

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. Yes ☐ No ☐

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

The aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant was $2,880,555,000 computed using the last sales price of $57.25 per share of the registrant's common stock on June 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 8, 2019, 50,347,571 shares of the registrant's common stock, par value $0.01 per share, were outstanding.

Documents Incorporated by Reference
Certain sections of our Proxy Statement for the 2019 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

On one or more occasions, we may make statements in this Annual Report on Form 10-K 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 Annual 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;
- 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 I, Item 1A of this Annual Report on Form 10-K.

From time to time, oral or written forward-looking statements are also included in our reports on Forms 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 Annual Report on Form 10-K, our reports on Forms 10-Q and 8-K, 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 Annual Report on Form 10-K, 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 Annual Report on Form 10-K 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 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.

GLOSSARY

Accounting Standards Codification (ASC) - The single source of authoritative nongovernmental GAAP, which supersedes all existing accounting standards.

Allowance for Funds Used During Construction (AFUDC) - A regulatory accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Base-Load - The minimum amount of electric power or natural gas delivered or required over a given period of time at a steady rate. The minimum continuous load or demand in a power system over a given period of time usually is not temperature sensitive.

Base-Load Capacity - The generating equipment normally operated to serve loads on an around-the-clock basis.

Capacity - The amount represents the maximum output of electricity a generator can produce and is related to peak demand. We must maintain a level of available capacity sufficient to meet peak demand with a sufficient reserve.

COD - commercial operating date.

Commercial Customers - consists primarily of main street businesses, shopping malls, grocery stores, gas stations, bars and restaurants, professional offices, hospitals and medical offices, motels, and hotels.

Cushion Gas - The natural gas required in a gas storage reservoir to maintain a pressure sufficient to permit recovery of stored gas.

DGGS - The Dave Gates Generating Station at Mill Creek, a 150 MW natural gas fired facility, which provides up to 105 MW of regulation service.

Environmental Protection Agency (EPA) - A Federal agency charged with protecting the environment.

Federal Energy Regulatory Commission (FERC) - The Federal agency that has jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related services pricing, oil pipeline rates and gas pipeline certification.

Franchise - A special privilege conferred by a unit of state or local government on an individual or corporation to occupy and use the public ways and streets for benefit to the public at large. Local distribution companies typically have franchises for utility service granted by state or local governments.

GAAP - Accounting principles generally accepted in the United States of America.

Hedging - Entering into transactions to manage various types of risk (e.g. commodity risk).

Industrial Customers - consists primarily of manufacturing and processing businesses that turn raw materials into products.

Lignite Coal - The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It has high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis.

Midcontinent Independent System Operator (MISO) - MISO is a nonprofit organization created in compliance with FERC as a regional transmission organization, to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing the energy markets, managing transmission constraints, managing the day-ahead, real-time and financial transmission rights markets, and managing the ancillary market.

Midwest Reliability Organization (MRO) - MRO is one of eight regional electric reliability councils under NERC.

Montana Public Service Commission (MPSC) - The state agency that regulates public utilities doing business in Montana.

Nameplate Capacity - the intended full-load sustained output of a generating facility. Nameplate capacity is the number registered with authorities for classifying the power output of a power station usually expressed in megawatts (MW).

Nebraska Public Service Commission (NPSC) - The state agency that regulates public utilities doing business in Nebraska.

North American Electric Reliability Corporation (NERC) - NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States. NERC's major responsibilities include developing standards for power system operation, monitoring and enforcing compliance with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.

Open Access - Non-discriminatory, fully equal access to transportation or transmission services offered by a pipeline or electric utility.

Open Access Transmission Tariff (OATT) -The OATT, which is established by the FERC, defines the terms and conditions of point-to-point and network integration transmission services offered by us, and requires that transmission owners provide open, non-discriminatory access on their transmission system to transmission customers.

Peak Load - A measure of the maximum amount of energy delivered at a point in time.

Qualifying Facility (QF) - As defined under the Public Utility Regulatory Policies Act of 1978 (PURPA), a QF sells power to a regulated utility at a price agreed to by the parties or determined by a public service commission that is intended to be equal to that which the utility would otherwise pay if it were to generate its own power or buy power from another source.

Regulation Services - FERC jurisdictional services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services are also referred to as ancillary services and include regulating reserves, load balancing and voltage support.

Securities and Exchange Commission (SEC) - The U.S. agency charged with protecting investors, maintaining fair, orderly and efficient markets and facilitating capital formation.

South Dakota Public Utilities Commission (SDPUC) - The state agency that regulates public utilities doing business in South Dakota.

Southwest Power Pool (SPP) - A nonprofit organization created in compliance with FERC as a regional transmission organization to ensure reliable supplies of power, adequate transmission infrastructure, and a competitive wholesale electricity marketplace. SPP also serves as a regional electric reliability entity under NERC.

Tariffs - A collection of the rate schedules and service rules authorized by a federal or state commission. It lists the rates a regulated entity will charge to provide service to its customers as well as the terms and conditions that it will follow in providing service.

Tolling Contract - An arrangement whereby a party moves fuel to a power generator and receives kilowatt hours (kWh) in return for a pre-established fee.

Transmission - The flow of electricity from generating stations over high voltage lines to substations. The electricity then flows from the substations into a distribution network.

Western Area Power Administration (WAPA) - A federal power-marketing administration and electric transmission agency established by Congress.

Western Electricity Coordination Council (WECC) - WECC is one of eight regional electric reliability councils under NERC.

Measurements:

Billion Cubic Feet (Bcf) - A unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.

British Thermal Unit (Btu) - a basic unit used to measure natural gas; the amount of natural gas needed to raise the temperature of one pound of water by one degree Fahrenheit.

Degree-Day - A measure of the coldness / warmness of the weather experienced, based on the extent to which the daily mean temperature falls below or above a reference temperature.

Dekatherm - A measurement of natural gas; ten therms or one million Btu.

Kilovolt (kV) - A unit of electrical power equal to one thousand volts.

Megawatt (MW) - A unit of electrical power equal to one million watts or one thousand kilowatts.

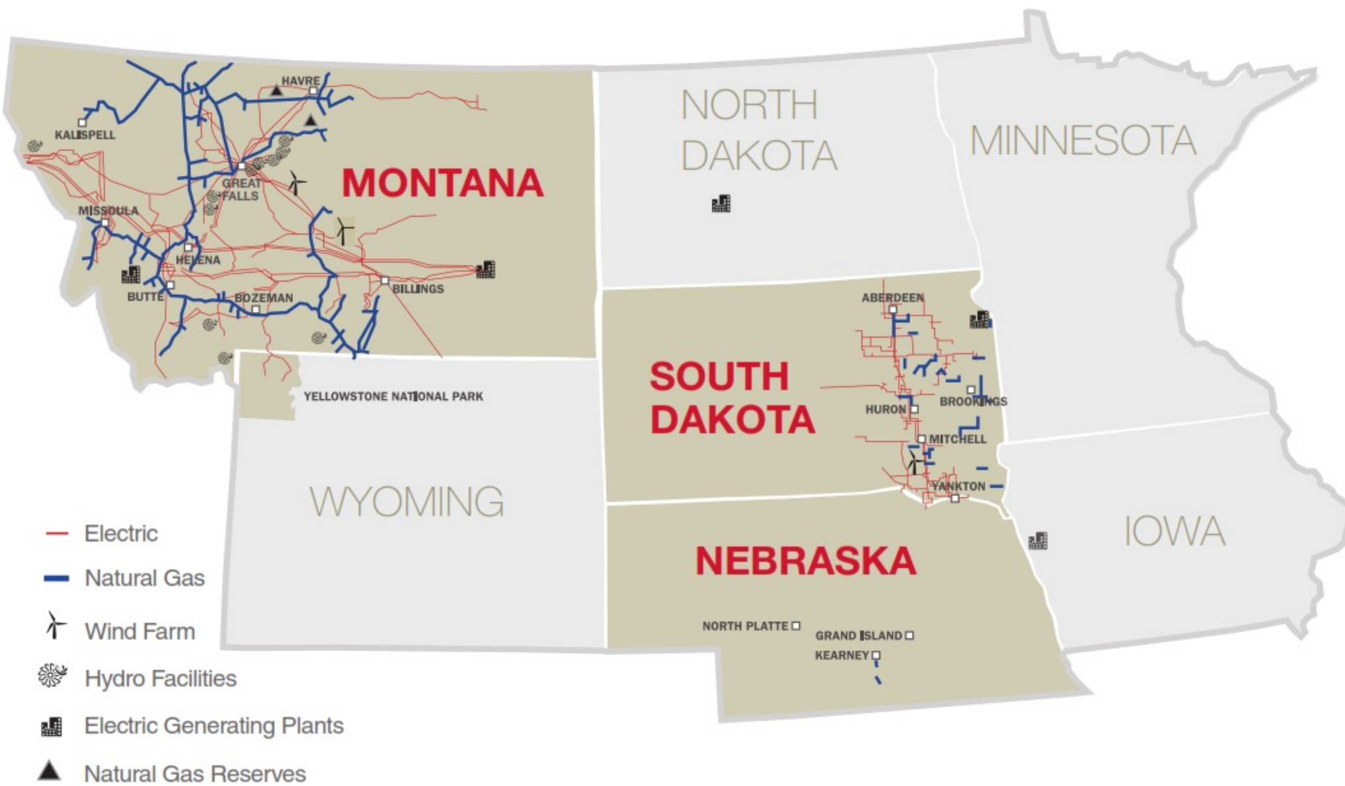
Megawatt Hour (MWH) - One million watt-hours of electric energy. A unit of electrical energy which equals one megawatt of power used for one hour.

ITEM 1. BUSINESS

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 726,400 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

We manage our businesses by the nature of services provided, and operate principally in three business segments: electric utility operations; natural gas utility operations; and all other, which primarily consists of unallocated corporate costs. Our electric utility operations include the generation, purchase, transmission and distribution of electricity, and our natural gas utility operations include the production, purchase, transmission, storage, and distribution of natural gas. Our customer base consists of a mix of residential, commercial, and diversified industrial customers.



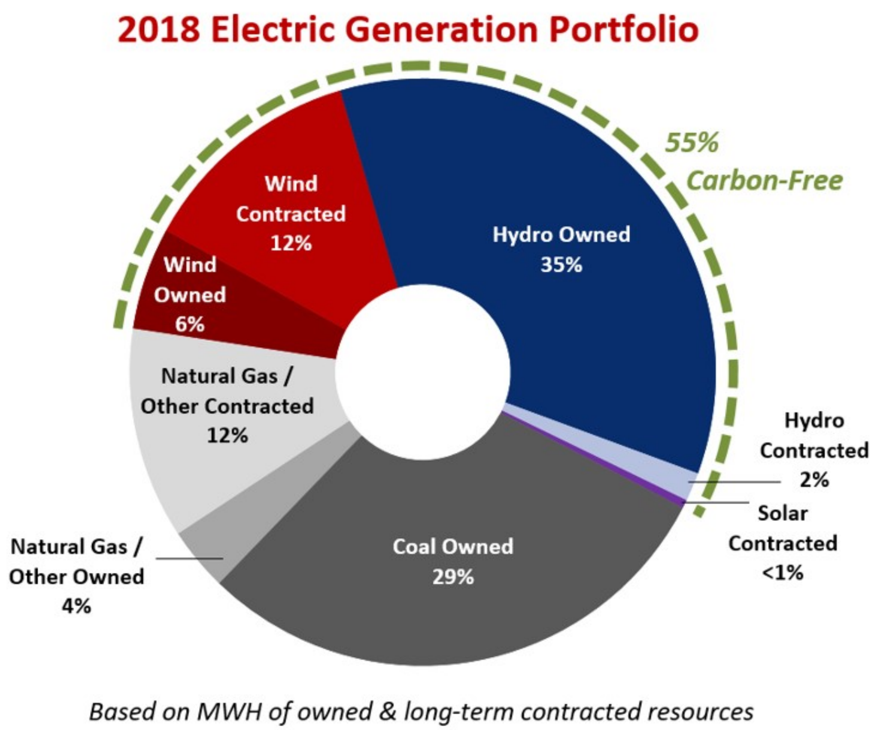
NorthWestern Energy - Delivering a Bright Future

We provide essential energy infrastructure and valuable services that enrich lives and empower communities while serving as long-term partners to our customers and communities. We are working to deliver safe, reliable, and innovative energy solutions that create value for customers, communities, employees, and investors. This includes bridging our history as a regulated utility safely providing low-cost and reliable service with our future as a globally-aware company offering a broader array of services performed by highly-adaptable and skilled employees.

Sustainability

We are focused on meeting current energy infrastructure and service needs at a reasonable and fair cost for today's customers while ensuring the ability to meet the needs of tomorrow's customers. "Sustainability" requires meeting economic, societal, and environmental objectives. As a provider of essential infrastructure and service, a sustainable enterprise is vital to our customers and communities, as well as to our investors and employees. For further information on our environmental, social, governance, and sustainability-related (ESG) efforts see our reports on *Environmental Stewardship: Our Commitment in Action* and our ESG reporting template available at www.northwesternenergy.com.

We strive to balance legal requirements to provide cost-effective, reliable and stably priced energy with being good stewards of natural resources, with a diligent focus on sustainability. We own a mix of clean and carbon-free energy resources balanced with traditional energy sources that help us deliver affordable and reliable electricity to our customers 24/7. We support cost-effective energy efficiency programs and low or carbon-free resources as part of our diverse supply portfolio. In 2018, approximately 55% of our retail needs originated from carbon-free resources.



ELECTRIC OPERATIONS

Our electric utility operations include the generation, purchase, transmission, and distribution of electricity. Our electric utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of our largest customers is not reasonably likely to have a material adverse effect on our financial condition. Our electric utility operations are seasonal and weather patterns can have a material impact on operating performance. Consumption of electricity is often greater in the summer and winter months for cooling and heating, respectively.

Montana

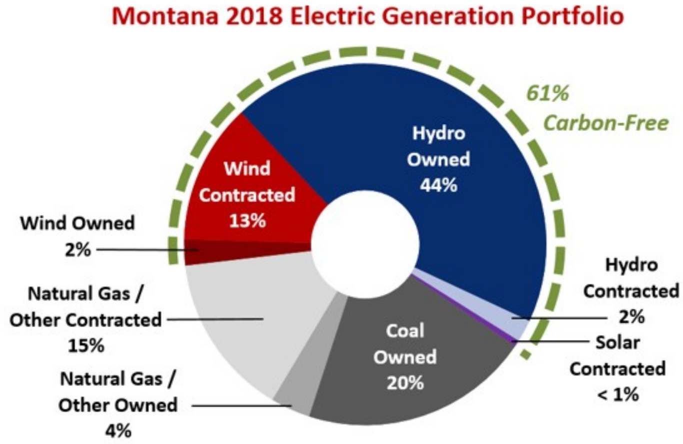
Our regulated electric utility business in Montana includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73% of Montana's land area, and includes a 2017 census estimated population of approximately 922,900. During 2018, we delivered electricity to approximately 374,000 customers in 208 communities and their surrounding rural areas, 11 rural electric cooperatives and, in Wyoming, to the Yellowstone National Park. In 2018, by category, residential, commercial, industrial, and other sales accounted for approximately 42%, 48%, 6%, and 4%, respectively, of our Montana retail electric utility revenue. We also transmit electricity for nonregulated entities owning generation, and utilities, cooperatives, and power marketers serving the Montana electricity market. Our total control area peak demand was approximately 1,843 MWs on August 10, 2018. Our control area average demand for 2018 was approximately 1,307 MWs per hour, with total energy delivered of more than 11.45 million MWHs.

Our Montana electric transmission and distribution network consists of approximately 24,765 miles of overhead and underground transmission and distribution lines and 386 transmission and distribution substations. Our transmission system is directly interconnected with Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; WAPA; and Montana Alberta Tie Ltd. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase, and sale of power among all major electric systems in the west interconnecting with the winter-peaking northern and summer-peaking southern regions of the western power system. We provide wholesale transmission service and firm and non-firm transmission services for eligible transmission customers. Our 500 kV transmission system, which is jointly owned, along with our 230 kV and 161 kV facilities, form the key assets of our Montana transmission system. Lower voltage systems, which range from 50 kV to 115 kV, provide for local area service needs.

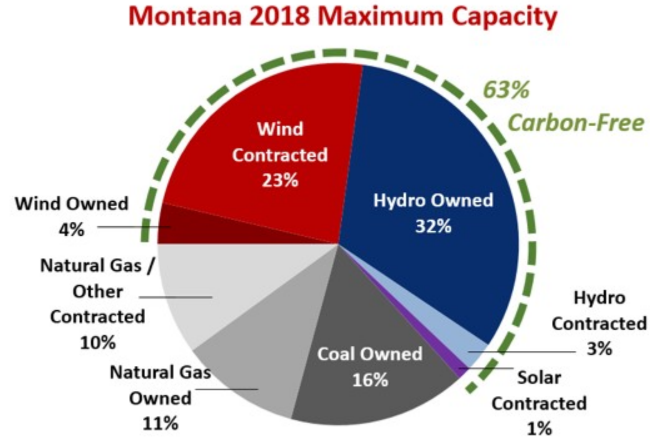
Energy Sources and Resource Planning

Resource planning is an important function necessary to meet our customers' future energy needs and is used to guide resource acquisition activities. We filed our last resource plan with the MPSC during 2016 and expect to file our draft 2019 resource plan during the first quarter of 2019. We have significant generation capacity deficits and negative reserve margins. In addition to our responsibility to meet peak demand, national reliability standards effective July 2016 increase the need for us to have greater dispatchable generation capacity available and be capable of increasing or decreasing output to address the irregular nature of intermittent generation such as wind or solar. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion.

The following charts depict the makeup of our current Montana portfolio. Hydro generation is by far our largest and most important resource, as it is reliable, dramatically lowers the portfolio's carbon intensity, and reduces economic risks associated with future carbon costs.



Based on MWH of owned & long-term contracted resources

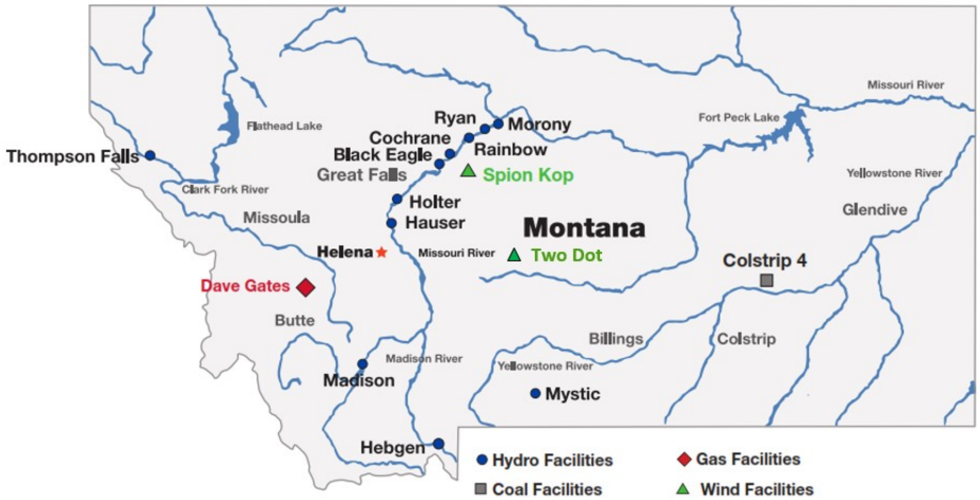


Our annual retail electric supply load requirements averaged approximately 760 MWs, with a peak load of approximately 1,200 MWs, and are supplied by owned and contracted resources and market purchases with multiple counterparties. Owned generation resources supplied approximately 65% of our retail load requirements for 2018. We expect that approximately 65% of our retail obligations will be met by owned generation in 2019 as well. In addition, QFs provide a total of 491 MWs of nameplate capacity, including 107 MWs of capacity from waste petroleum coke and waste coal, 351 MWs of capacity from wind, 16 MWs of capacity from hydro, and 17 MWs of capacity from solar projects, located in Montana. We have several other long and medium-term power purchase agreements including contracts for 135 MWs of wind generation and 21 MWs of seasonal base-load hydro supply. For 2019, including both owned and contracted resources, we have resources to provide over 90% of the energy requirements necessary to meet our forecasted retail load requirements.

Western Energy Imbalance Market

In November 2018, we announced our intent to enter the Western Energy Imbalance Market (EIM), operated by the California Independent System Operator (California ISO), in the spring of 2021. We studied the value and costs of the EIM for several years prior to the decision to participate in the Western EIM. Utilities in the western United States outside the California ISO have traditionally relied upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply. These utilities have limited capability to transact within the hour outside their balancing area. In contrast, energy imbalance markets use automated intra-hour economic dispatch of generation from committed resources to serve loads. The Western EIM is intended to reduce the power supply costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability. Participation in the Western EIM is voluntary and available to all balancing authorities in the western United States.

Generation Facilities



Details of these generating facilities are described in the following tables.

Hydro Facilities	COD	River Source	FERC License Expiration	Maximum Capacity (MW) (1)
Black Eagle	1927	Missouri	2040	21
Cochrane	1958	Missouri	2040	62
Hauser	1911	Missouri	2040	17
Holter	1918	Missouri	2040	53
Madison	1906	Madison	2040	8
Morony	1930	Missouri	2040	49
Mystic	1925	West Rosebud Creek	2050	12
Rainbow	1910/2013	Missouri	2040	64
Ryan	1915	Missouri	2040	68
Thompson Falls	1915	Clark Fork	2025	94
Total				**448**

(1) The Hebgen facility (0 MW net capacity) is excluded from the figures above. These are run-of-river dams except for Mystic, which is storage generation.

Other Facilities	Fuel Source	Ownership Interest	Maximum Capacity (MW)
Colstrip Unit 4, located near Colstrip in southeastern Montana	Sub-bituminous coal	30%	222
Dave Gates Generating Station (DGGS), located near Anaconda, Montana	Natural Gas	100%	150
Spion Kop Wind, located in Judith Basin County in Montana	Wind	100%	40
Two Dot Wind, located in Wheatland County in Montana	Wind	100%	11

Colstrip Unit 4 provides base-load supply and is operated by Talen Montana, LLC (Talen). Talen has a 30% ownership interest in Colstrip Unit 3. We have a reciprocal sharing agreement with Talen regarding the operation of Colstrip Units 3 and 4, in which each party receives 15% of the respective combined output and is responsible for 15% of the respective operating and construction costs, regardless of whether a particular cost is specified to Colstrip Unit 3 or 4. However, each party is responsible for its own fuel-related costs. Colstrip Unit 4 is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019.

DGGS typically provides regulation service, intra-hour balancing, contingency reserves, and peaking capacity. DGGS also provides approximately 7 MWs of retail base-load requirements.

The capacity of Spion Kop represents the nameplate MW, which varies from actual energy expected to be generated as wind resources are highly dependent upon weather conditions.

The capacity of Two Dot represents the upgraded nameplate MW achieved through a software upgrade. Two Dot has been approved as a community renewable energy project (CREP) by the MPSC.

Renewable portfolio standards (RPS) enacted in Montana currently require that 15% of our annual electric supply portfolio be derived from eligible sources, including resources such as wind, biomass, solar, and small hydroelectric. Eligible resources used to serve our load generate renewable energy credits (RECs). Any RECs in excess of the annual requirements for a given year are carried forward for up to two years to meet future RPS needs. While our hydro generation assets acquired in 2014 are not eligible resources under the RPS, any qualifying additions would be eligible. Given contracts under negotiation and our portfolio resources, we expect to meet the Montana RPS requirements through the 2040s. The penalty for not meeting the RPS is up to $10 per MWH for each REC short of the requirement.

As a subset of the total RPS requirement, we were required to acquire, as of December 31, 2018, approximately 65 MW of CREPs. While we have made progress and believe we have taken all reasonable steps to meet this requirement, we have been unable to do so to date 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 waivers for 2012 through 2016. We expect to file waiver requests for 2017 and 2018. If the requested waivers are not granted, we may be liable for penalties, although we believe the statutory penalty for failure to acquire sufficient energy does not apply to the acquisition of CREP resources. If the MPSC imposes a penalty, the amount of the penalty would depend on how the MPSC calculates the energy that a CREP would have produced.

South Dakota

Our South Dakota electric utility business operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties with a combined 2010 census population of approximately 226,200. We provide retail electricity to more than 63,800 customers in 110 communities in South Dakota. In 2018, by category, residential, commercial and other sales accounted for approximately 40%, 58%, and 2%, respectively, of our South Dakota retail electric utility revenue. Peak demand was approximately 330 MWs and the average load was approximately 200 MWs during the year ended December 31, 2018.

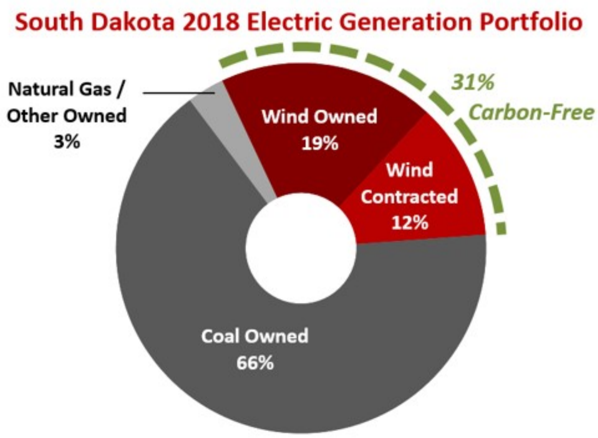
Our transmission and distribution network in South Dakota consists of approximately 3,572 miles of overhead and underground transmission and distribution lines as well as 128 substations. We have interconnection with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; Xcel Energy Inc.; and WAPA. We have emergency interconnections with the transmission facilities of East River Electric Cooperative, Inc. and West Central Electric Cooperative.

Energy Sources and Resource Planning

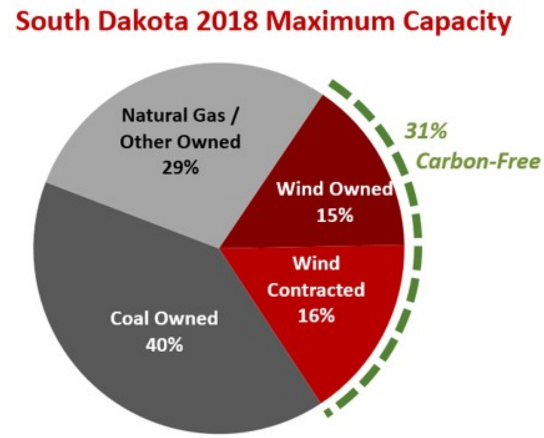
We have a resource plan that includes estimates of customer usage and programs to provide for the economic, reliable and timely supply of energy. We continue to update our load forecast to identify the future electric energy needs of our customers, and we evaluate additional generating capacity requirements on an ongoing basis. We submitted a plan in 2018 to provide for the modernization of our fleet, which is focused on improving reliability and flexibility. It also identifies a need of approximately 90MWs of existing generation that should be retired and replaced over the next 10 years to meet our goal of improved reliability and lower operating costs.

We use market purchases and peaking generation to provide peak supply in excess of our base-load capacity. We are a member of the SPP, which is a regional transmission organization that operates an organized energy market in the Central United States. As a market participant in SPP, we buy and sell wholesale energy and reserves in both day-ahead and real-time markets through the operation of a single, consolidated SPP balancing authority. We and other SPP members submit into the SPP market both offers to sell our generation and bids to purchase power to serve our load. SPP optimizes next-day and real-time generation dispatch across the region and provides participants with greater access to economic energy. Marketing activities in SPP are handled for us by a third-party provider acting as our agent.

Our sources of energy by type during 2018 were as follows:



Based on MWH of owned & long-term contracted resources



Generation Facilities

Details of our generating facilities are described further in the following chart:

Generation Facilities	Fuel Source	Nameplate Capacity (MW)	Ownership Interest	Owned Capacity (MW)
Big Stone Plant, located near Big Stone City in northeastern South Dakota	Sub-bituminous coal	475	23.4%	111
Coyote I Electric Generating Station, located near Beulah, North Dakota	Lignite coal	427	10.0%	43
Neal Electric Generating Unit No. 4, located near Sioux City, Iowa	Sub-bituminous coal	644	8.7%	56
Aberdeen Generating Unit, located near Aberdeen, South Dakota	Natural gas	52	100.0%	52
Beethoven Wind Project, located near Tripp, South Dakota	Wind	80	100.0%	80
Miscellaneous combustion turbine units and small diesel units (used only during peak periods)	Combination of fuel oil and natural gas		100.0%	98
Total Capacity				440

Our electric supply portfolio includes facilities that we own jointly with unaffiliated parties. Each of the jointly owned plants is subject to a joint management structure, and we are not the operator of any of these plants. Based on our ownership interest, we are entitled to a proportionate share of the capacity of our jointly owned plants and are responsible for a proportionate share of the operating costs. Additional resources in our supply portfolio include several wholly owned peaking units and one wholly owned wind project. The Beethoven wind project is an 80 MW nameplate facility. Actual output varies as wind generation resources are highly dependent upon weather conditions. We also purchase the output of four wind projects, three of which are QFs, under power purchase agreements.

The fuel for our jointly owned base-load generating plants is provided through supply contracts of various lengths with several coal companies. Coyote is a mine-mouth generating facility. Neal #4 and Big Stone receive their fuel supply via rail. The average delivered cost by type of fuel burned varies between generation facilities due to differences in transportation costs and owner purchasing power for coal supply. Changes in our fuel costs are passed on to customers through the operation of the fuel adjustment clause in our South Dakota tariffs.

We are a transmission-owning member in the SPP. Each year, we review all new or modified South Dakota transmission assets and transfer functional control of assets that qualify under the SPP Tariff to the SPP. To date, we have transferred control of over 340 line miles of 115 kV facilities and over 97 line miles of 69 kV facilities. All of our SPP controlled facilities reside in the Upper Missouri Zone (UMZ), which is also known as Zone 19 in the regional transmission organization. The Coyote, Big Stone, and Neal power plants, which we jointly own, are connected directly to the MISO system. Our ownership rights in the transmission lines from these plants to our distribution system allow us to move the power to our customers. Along with operating the transmission system, SPP also coordinates regional transmission planning for all members of the organization.

NATURAL GAS OPERATIONS

Our natural gas utility operations include the production, purchase, transmission, storage, and distribution of natural gas. Our natural gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of our largest customers is not reasonably likely to have a material adverse effect on our financial condition. Our gas utility business is seasonal and weather patterns can have a material impact on operating performance. Because natural gas is used primarily 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.

Montana

Our regulated natural gas utility business in Montana includes production, storage, transmission and distribution. During 2018, we distributed natural gas to approximately 199,200 customers in 118 Montana communities over a system that consists of approximately 4,781 miles of underground distribution pipelines. We also serve several smaller distribution companies that provide service to approximately 37,000 customers. We transmit natural gas in Montana from production receipt points and storage facilities to distribution points and other nonaffiliated transmission systems. We transported natural gas volumes of approximately 42.3 Bcf during the year ended December 31, 2018.

Our natural gas transmission system consists of more than 2,100 miles of pipeline, which vary in diameter from two inches to 24 inches, and serve 149 city gate stations. We have connections in Montana with four major, unaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, and Spur Energy. Eight compressor sites provide more than 34,000 horsepower, capable of moving more than 335,000 dekatherms per day. In addition, we own and operate two transmission pipelines through our subsidiaries, Canadian-Montana Pipe Line Corporation and Havre Pipeline Company, LLC.

Natural gas is used primarily for residential and commercial heating, and for fuel for two electric generating facilities. The demand for natural gas largely depends upon weather conditions. Our Montana retail natural gas supply requirements for the year ended December 31, 2018, were approximately 21.8 Bcf. Our Montana natural gas supply requirements for electric generation fuel for the year ended December 31, 2018, were approximately 3.8 Bcf. We have contracted with several major producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements. Our natural gas supply requirements are fulfilled through third-party fixed-term purchase contracts, short-term market purchases and owned production. Our portfolio approach to natural gas supply is intended to enable us to maintain a diversified supply of natural gas sufficient to meet our supply requirements. We benefit from direct access to suppliers in significant natural gas producing regions in the United States, primarily the Rocky Mountains (Colorado), Montana, and Alberta, Canada.

Owned Production and Storage

Since 2010, we have acquired gas production and gathering system assets as a part of an overall strategy to provide rate stability and customer value: as we own these assets, which are regulated, our customers are protected from potential price spikes in the market. As of December 31, 2018, these owned reserves totaled approximately 51.7 Bcf and are estimated to provide approximately 4.1 Bcf in 2019, or about 19 percent of our expected annual retail natural gas load in Montana. In addition, we own and operate three working natural gas storage fields in Montana with aggregate working gas capacity of approximately 17.75 Bcf and maximum aggregate daily deliverability of approximately 195,000 dekatherms.

South Dakota and Nebraska

We provide natural gas to approximately 89,400 customers in 59 South Dakota communities and three Nebraska communities. We have approximately 2,437 miles of underground distribution pipelines and 55 miles of transmission pipeline in South Dakota and Nebraska. In South Dakota, we also transport natural gas for nine gas-marketing firms and three large end-user accounts. In Nebraska, we transport natural gas for four gas-marketing firms and one end-user account. We delivered approximately 28.3 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 3.5 Bcf of third-party transportation volume on our Nebraska distribution system during 2018.

Our South Dakota natural gas supply requirements for the year ended December 31, 2018, were approximately 6.7 Bcf. We contract with a third party under an asset management agreement to manage transportation and storage of supply to minimize cost and price volatility to our customers. In Nebraska, our natural gas supply requirements for the year ended December 31, 2018, were approximately 4.9 Bcf. We contract with a third party under an asset management agreement that includes pipeline capacity, supply, and asset optimization activities. To supplement firm gas supplies in South Dakota and Nebraska, we contract for firm natural gas storage services to meet the heating season and peak day requirements of our customers.

Municipal Natural Gas Franchise Agreements

We have municipal franchises to provide natural gas service in the communities we serve. The terms of the franchises vary by community. Our Montana franchises typically have a fixed 10-year term and continue for additional 10-year terms unless and until canceled, with 5 years notice. The maximum term permitted under Nebraska law for these franchises is 25 years while the maximum term permitted under South Dakota law is 20 years. Our policy generally is to seek renewal or extension of a franchise in the last year of its term. We continue to serve those customers while we obtain formal renewals. During the next five years, eleven of our Montana franchises are scheduled to reach the end of their fixed term, which account for approximately 62,000 or 31 percent of our Montana natural gas customers. Seven of our South Dakota franchises and two franchises in Nebraska, which account for approximately 35,400 or 40% of our South Dakota and Nebraska natural gas customers, are scheduled to reach the end of their fixed term during the next five years. We do not anticipate termination of any of these franchises.

REGULATION

Base rates are the rates that are intended to allow us the opportunity to collect from our customers total revenues (revenue requirements) equal to our cost of providing delivery and rate-based supply services, plus a reasonable rate of return on invested capital. We have both electric and natural gas base rates and cost recovery clauses. We may ask the respective regulatory commission to increase base rates from time to time. Rate increases are normally granted based on historical data and those increases may not always keep pace with increasing costs. For more information on current regulatory matters, see Note 4 - Regulatory Matters, to the Consolidated Financial Statements.

The following is a summary of our rate base and authorized rates of return in each jurisdiction:

Jurisdiction and Service	Implementation Date	Authorized Rate Base (millions) (1)	Estimated Rate Base (millions) (2)	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Montana electric delivery (3)	July 2011	$632.5	$1,233.0	7.92%	10.25%	48%
Montana - DGGS (3)	January 2011	172.7	167.8	8.16%	10.25%	50%
Montana - Colstrip Unit 4	January 2009	400.4	280.4	8.25%	10.00%	50%
Montana Spion Kop	December 2012	69.8	54.1	7.00%	10.00%	48%
Montana hydro assets	November 2014	841.8	777.4	6.91%	9.80%	48%
Montana natural gas delivery and production	September 2017	430.2	451.4	6.96%	9.55%	46.79%
Total Montana		$2,547.4	$2,964.1			
South Dakota electric (4)	December 2015	$557.3	$587.8	7.24%	n/a	n/a
South Dakota natural gas (4)	December 2011	65.9	61.6	7.80%	n/a	n/a
Total South Dakota		$623.2	$649.4			
Nebraska natural gas (4)	December 2007	$24.3	$26.5	8.49%	10.40%	n/a
		$3,194.9	$3,640.0			

(1) Rate base reflects amounts on which we are authorized to earn a return.
(2) Rate base amounts are estimated as of December 31, 2018.
(3) The revenue requirement associated with the FERC regulated portion of Montana electric transmission and DGGS are included as revenue credits to our MPSC jurisdictional customers. Therefore, we do not separately reflect FERC authorized rate base or authorized returns.
(4) For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms.

MPSC Regulation

Our Montana operations are subject to the jurisdiction of the MPSC with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations, including when we issue, assume, or guarantee securities in Montana, or when we create liens on our regulated Montana properties. We have an obligation to provide service to our customers with an opportunity to earn a regulated rate of return.

Electric Supply Tracker - Effective July 1, 2017, the Montana legislature granted the MPSC discretion whether to approve an electric supply cost tracking mechanism. After considering our application in a contested case proceeding, the MPSC approved an electric Power Cost and Credit Adjustment Mechanism (PCCAM) effective July 1, 2017 that incorporates sharing of a portion of the business risk or benefit associated with the cost of power purchased and fuel used to generate electricity. Customer prices may be adjusted annually to absorb a portion of the difference between base revenues and actual costs for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to a review by the MPSC to determine if electric supply procurement activities are prudent. If the MPSC subsequently determines that a procurement activity was imprudent, then it may disallow recovery of such costs. For additional information, see the Overview section in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Natural Gas Supply Tracker - Rates for our Montana natural gas supply are set by the MPSC. Certain supply rates are adjusted on a monthly basis for volumes and costs during each July to June 12-month tracking period. Annually, supply rates are adjusted to include any differences in the previous tracking year's actual to estimated information for recovery during the subsequent tracking year. We submit annual natural gas tracker filings for the actual 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our natural gas energy supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, then it may disallow such costs.

***Montana Property Tax Tracker* -** We file an annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflects the incremental property taxes since our last base rate filing adjusted for the associated income tax benefit.

SDPUC Regulation

Our South Dakota operations are subject to SDPUC jurisdiction with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our electric and natural gas operations. Our retail electric rates, approved by the SDPUC, provide several options for residential, commercial and industrial customers, including dual-fuel, interruptible, special all-electric heating, and other special rates. Our retail natural gas tariffs include gas transportation rates for transportation through our distribution systems by customers and natural gas marketers from the interstate pipelines at which our systems take delivery to the end-user. Such transporting customers nominate the amount of natural gas to be delivered daily. Daily, we monitor usage for these customers and balance it against their respective supply agreements.

An electric adjustment clause provides for quarterly adjustment based on differences in the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid and commission-approved fuel incentives. The adjustment goes into effect upon filing, and is deemed approved within 10 days after the information filing unless the SDPUC staff requests changes during that period. A purchased gas adjustment provision in our natural gas rate schedules permits the monthly adjustment of charges to customers to reflect increases or decreases in purchased gas, gas transportation and ad valorem taxes.

NPSC Regulation

Our Nebraska natural gas rates and terms and conditions of service for residential and smaller commercial customers are regulated by the NPSC. High volume customers are not subject to such regulation, but can file complaints if they allege discriminatory treatment. Under the Nebraska State Natural Gas Regulation Act, a regulated natural gas utility may propose a change in rates to its regulated customers, if it files an application for a rate increase with the NPSC and with the communities in which it serves customers. The utility may negotiate with those communities for a settlement with regard to the rate change if the affected communities representing more than 50% of the affected ratepayers agree to direct negotiations, or it may proceed to have the NPSC review the filing and make a determination. Our tariffs have been accepted by the NPSC, and the NPSC has adopted certain rules governing the terms and conditions of service of regulated natural gas utilities. Our retail natural gas tariffs provide residential, general service and commercial and industrial options, as well as firm and interruptible transportation service. A purchased gas adjustment clause provides for adjustments based on changes in gas supply and interstate pipeline transportation costs.

FERC Regulation

We are subject to FERC's jurisdiction and regulations with respect to rates for electric transmission service in interstate commerce and electricity sold at wholesale rates, hydro licensing and operations, the issuance of certain securities, incurrence of certain long-term debt, and compliance with mandatory reliability regulations, among other things. Under FERC's open access transmission policy promulgated in Order No. 888, as owners of transmission facilities, we are required to provide open access to our transmission facilities under filed tariffs at cost-based rates. In addition, we are required to comply with FERC's Standards of Conduct for Transmission Providers.

Our Montana wholesale transmission customers, such as cooperatives, are served under our OATT, which is on file with FERC. The OATT defines the terms, conditions and rates of our Montana transmission service, including ancillary services. Our South Dakota transmission operations are in the SPP and transmission service is provided under the SPP OATT.

Our natural gas transportation pipelines are generally not subject to FERC's jurisdiction, although we are subject to state regulation. We conduct limited interstate transportation in Montana and South Dakota that is subject to FERC jurisdiction, and FERC has allowed the MPSC and SDPUC to set the rates for this interstate service. We have capacity agreements in South Dakota and Nebraska with interstate pipelines that are also subject to FERC jurisdiction.

Our hydroelectric generating facilities are licensed by the FERC. In connection with the relicensing of these generating facilities, applicable law permits the FERC to issue a new license to the existing licensee or to a new licensee, and alternatively allows the U.S. government to take over the facility. If the existing licensee is not relicensed, it is compensated for its net investment in the facility, not to exceed the fair value of the property taken, plus reasonable severance damages to other property affected by the lack of relicensing.

***Reliability Standards* -** We must comply with the standards and requirements that apply to the NERC functions for which we have registered in both the MRO for our South Dakota operations and the WECC for our Montana operations. WECC and the MRO have responsibility for monitoring and enforcing compliance with the FERC approved mandatory reliability standards within their respective regions. Additional reliability standards continue to be developed and will be adopted in the future. We expect that the existing reliability standards will change often as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement.

ENVIRONMENTAL

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 and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are issued, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

We strive to comply with all environmental regulations applicable to our operations. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, what effect future laws or regulations may have on our operations. The EPA is in the process of proposing and finalizing a number of environmental regulations that will directly affect the electric industry over the coming years. These initiatives cover all sources - air, water and waste. For more information on environmental regulations and contingencies and related capital expenditures, see Note 19 - Commitments and Contingencies, to the Consolidated Financial Statements.

CORPORATE INFORMATION AND WEBSITE

We were incorporated in Delaware in November 1923. Our Internet address is http://www.northwesternenergy.com. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments, along with our annual report to shareholders and other information related to us, are available, free of charge, on our Internet website as soon as reasonably practicable after we electronically file those documents with, or otherwise furnish them to, the SEC. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, NorthWestern Corporation, 3010 W. 69th Street, Sioux Falls, South Dakota 57108 and our telephone number is (605) 978-2900. References to our website in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report.

EMPLOYEES

As of December 31, 2018, we had 1,528 employees. Of these, 1,220 employees were in Montana and 308 were in South Dakota or Nebraska. Of our Montana employees, 446 were covered by seven collective bargaining agreements involving five unions. Six of these agreements were renegotiated in 2016 with terms that will expire in 2020. One of these agreements was renegotiated in 2017 with a term that will expire in 2021. One additional collective bargaining agreement, representing six employees, is currently being negotiated, and those negotiations are expected to be completed during the first quarter of 2019. Of our South Dakota and Nebraska employees, 185 were covered by a collective bargaining agreement that was renegotiated in 2016 with a term that expires at the end of 2019. We consider our relations with employees to be good.

Executive Officer	Current Title and Prior Employment	Age on Feb. 8, 2019
Robert C. Rowe	President, Chief Executive Officer and Director since August 2008. Prior to joining NorthWestern, Mr. Rowe was a co-founder and senior partner at Balhoff, Rowe & Williams, LLC, a specialized national professional services firm providing financial and regulatory advice to clients in the telecommunications and energy industries (January 2005-August, 2008); and served as Chairman and Commissioner of the Montana Public Service Commission (1993–2004).	63
Brian B. Bird	Chief Financial Officer since December 2003. Prior to joining NorthWestern, Mr. Bird was Chief Financial Officer and Principal of Insight Energy, Inc., a Chicago-based independent power generation development company (2002-2003). Previously, he was Vice President and Treasurer of NRG Energy, Inc., in Minneapolis, MN (1997-2002). Mr. Bird serves on the board of directors of a NorthWestern subsidiary.	56
Michael R. Cashell	Vice President - Transmission since May 2011; formerly Chief Transmission Officer since November 2007; formerly Director Transmission Marketing and Business Planning since 2003. Mr. Cashell serves on the board of directors of a NorthWestern subsidiary.	56
Heather H. Grahame	Vice President - General Counsel and Regulatory and Federal Government Affairs since January 2018; formerly Vice President and General Counsel since August 2010. Prior to joining NorthWestern, Ms. Grahame was a partner in the law firm of Dorsey & Whitney, LLP, where she co-chaired its Telecommunications practice (1999-2010).	63
John D. Hines	Vice President - Supply and Montana Government Affairs since January 2018; formerly Vice President - Supply since May 2011; formerly Chief Energy Supply Officer since January 2008; formerly Director - Energy Supply Planning since 2006. Previously, Mr. Hines served as the Montana representative to the Northwest Power and Conservation Council (2003-2006).	60
Crystal D. Lail	Vice President and Controller since October 2015; formerly Assistant Controller since February 2008 and, prior to that an SEC Reporting Manager. Prior to joining NorthWestern, Ms. Lail was an auditor for KPMG LLP.	40
Curtis T. Pohl	Vice President - Distribution since May 2011; formerly Vice President-Retail Operations since September 2005; Vice President-Distribution Operations since August 2003; formerly Vice President-South Dakota/Nebraska Operations since June 2002; formerly Vice President-Engineering and Construction since June 1999. Mr. Pohl serves on the board of directors of a NorthWestern subsidiary.	54
Bobbi L. Schroeppel	Vice President, Customer Care, Communications and Human Resources since May 2009, formerly Vice President-Customer Care and Communications since September 2005; formerly Vice President-Customer Care since June 2002; formerly Director-Staff Activities and Corporate Strategy since August 2001; formerly Director-Corporate Strategy since June 2000.	50

Officers are elected annually by, and hold office at the pleasure of the Board of Directors (Board), and do not serve a “term of office” as such.

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.

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.

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 provide service at rates established by several regulatory commissions. These rates are generally set based on an analysis of our costs incurred in a historical test year. 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. Thus, the rates we are allowed to charge may or may not match our costs at any given time. For instance, our Montana electric utility is regulated by the MPSC and 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 methodology.

While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there 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 to rate cases, our cost tracking mechanisms are a significant component of how we recover our costs.

Montana Regulation - We have received several unfavorable regulatory rulings in Montana, including:

- In 2018, the MPSC revised our recovery of prudently incurred supply costs to increase our risk by incorporating a sharing mechanism, which includes a +/- $4.1 million deadband applied to the difference between actual costs and revenues, with differences beyond the deadband shared by allocating 90% to customers and 10% to shareholders.
- In 2018, the MPSC issued an order in our 2017 property tax tracker filing reducing our recovery of Montana property taxes between general rate filings by applying an alternate allocation methodology.
- In 2017, the MPSC revised our QF tariff for standard QF rates for small QFs (3 MW or less) to establish a maximum contract length of 15 years and a substantially lower rate for future QF contracts. The MPSC also applied the 15-year contract term to the economic evaluation of our future owned and contracted electric supply resources. As a result, we terminated our competitive solicitation process to address our intermittent capacity and reserve margin needs in Montana.
- In 2016, the MPSC disallowed replacement power costs from a 2013 outage at Colstrip Unit 4 requested in our electric tracker filings.
- In 2015, the MPSC issued an order eliminating the lost revenue adjustment mechanism, which allowed for recovery of fixed costs not recovered as a result of our energy efficiency program.
- In 2013, the MPSC concluded that costs associated with a 2012 outage at DGGS were imprudently incurred, and disallowed recovery.

We submitted a general electric rate case filing with the MPSC in September 2018. We cannot predict how the MPSC may address this filing. If the MPSC determines our request is not supported and / or decreases overall electric rates, it could have a material adverse effect on our operating and financial results.

FERC & Other Regulation - We must comply with established reliability standards and requirements including Critical Infrastructure Protection (CIP) Reliability Standards, which apply to the 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.

Early closure or unscheduled plant outages of our owned and jointly owned electric generating facilities due to operational or economic factors, environmental risks or litigation could have a material adverse impact on our results of operations and liquidity. We also rely on a limited number of suppliers of coal for our electric generation, making us

vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply.

Operation of electric generating facilities involves risks. 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, which may not be recovered from customers.

In addition, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the continued operation of certain facilities, expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of 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 greenhouse gas or other emissions or coal combustion residuals (CCR) disposal and storage. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities.

Early closure of our generation facilities due to economic conditions, environmental regulations and / or litigation could result in regulatory impairments or increased cost of operations. 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 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. 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 Colstrip currently share the operating costs pursuant to the terms of an operating agreement among the owners of Units 3 and 4 and a common facilities agreement among the owners of all four units. When Units 1 and 2 discontinue operation, we anticipate incurring incremental 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. This reduction would be incorporated in our next general electric rate filing after the closure of Units 1 and 2, resulting in lower revenue credits to certain customers. In addition, the remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Two of the other joint owners have entered into settlements with regulators and a third has filed a petition with its regulators to accelerate the recovery of their investment in Colstrip Units 3 and 4 by using a depreciable life through 2027, but have not established a date for closure. Recovery of costs associated with the shut-down of the facility prior to the end of the useful life would be subject to MPSC approval.

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. This 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.

Coal Supply - Colstrip Units 3 and 4 are supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019. We and other joint owners are discussing new coal supply and transportation agreements, which anticipate expansion of the coal mine. This expansion requires environmental reviews and permitting. We cannot predict when or if those permits will be granted. Our coal supply and transportation agreements are with Western Energy Company (WeCo), a subsidiary of Westmoreland Coal Co. (Westmoreland). Westmoreland, along with WeCo filed for Chapter 11 bankruptcy protection on October 9, 2018. An auction was held for Westmoreland's core assets, including its interest in WeCo and the mine adjacent to Colstrip, and no qualified bids were received. As a result a lenders group is expected to acquire Westmoreland's core assets. During the course of the bankruptcy, WeCo may choose to assume or reject the existing coal supply and transportation agreements. WeCo indicated that it intends to reject the existing cost plus coal supply agreement. If WeCo rejects the existing agreement, the fuel supply to Units 3 and 4 may be interrupted until new arrangements are in place. In addition, any new arrangements may have higher costs than the existing cost plus agreement. We cannot predict the effect the Westmoreland bankruptcy may have on the ongoing operations of the facility.

We are a captive rail shipper of the Burlington Northern Santa Fe Railway for shipments of coal to the Big Stone Plant (our largest source of generation in South Dakota), making us vulnerable to railroad capacity and operational issues and/or increased prices for coal transportation from a sole supplier.

Our electric and natural gas transmission and distribution 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 and natural gas operations are a variety of hazards and operating risks, such as fires, electric contacts, leaks, explosions, catastrophic failures and mechanical problems. These risks could cause a loss of human life, 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 powerline igniting a fire. Fires alleged to have been caused by our system could expose us to significant damage claims on theories such as strict liability, negligence, gross negligence, trespass, inverse condemnation, and others.

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 (such as hacking and viruses) and physical security breaches and other disruptive activities of individuals or groups. 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, 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, or 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.

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 power cost adjustment mechanism 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.

We are subject to extensive and changing environmental laws and regulations and potential environmental liabilities, which could have a material adverse effect on our liquidity and results of operations.

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 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 judicial 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.

In October 2015, the EPA published standards for states to implement to control greenhouse gas (GHG) emissions from existing electric generating units. These standards are referred to as the Clean Power Plan (CPP). We, along with a number of states and other parties, filed lawsuits against the EPA standards. The EPA proposed to repeal the CPP in October 2017. On August 31, 2018, EPA published a proposed rule, the Affordable Clean Energy Rule (ACE), which is intended to serve as a replacement for the CPP. If finalized as proposed, it is expected that the ACE would generally require a lower level of carbon dioxide (CO_2) emission reductions than the CPP and provide more regulatory flexibility to individual states. We cannot predict whether CPP will be repealed or whether the ACE will be implemented in its current form.

If 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.

Our need to acquire flexible energy supply and capacity in the market to meet our electric load serving obligations in Montana may have risks. Our electric and natural gas portfolios have a significant percentage of market purchases and market prices for power and natural gas and are subject to forces that are often not predictable and which can result in price volatility and general market disruption, adversely affecting our costs and ability to manage our energy portfolio and procure required energy supply, which ultimately could have an adverse effect on liquidity and results of operations.

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 our Montana electric supply recovery mechanism.

We are obligated to supply power to retail customers and certain wholesale customers. In Montana, approximately 46% of our peak requirements are served through market purchases. We rely upon contracts with counterparties and market purchases to fulfill this need; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to us. The suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us.

In addition, a significant number of base-load generation facilities, which may also serve to meet peak requirements, in the region are being retired or are scheduled to be retired in the next five to ten years. A decrease in the region's capacity may impair the reliability of the grid, particularly during peak demand periods. This may also reduce our ability to rely upon contracts with counterparties to fulfill our ability to serve customers' needs.

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.

We are also 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 existing, and potential future, federal and state legislation. In the planning and management of our operations, we must address the effects of legislation within a regulatory framework. Federal and state laws can significantly impact our operations, whether it is new or revised statutes directly affecting the electric and gas industry, or other issues such as taxes.

In addition, new or revised statutes can also materially affect our operations through impacting existing regulations or requiring new regulations. These changes are ongoing, and we cannot predict the future course of changes or the ultimate effect that this changing environment will have on us. Changes in laws, and the resulting regulations and tariffs and how they are implemented and interpreted, may have a material adverse effect on our financial condition, results of operations and cash flows.

On June 22, 2016, the Securing America's Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act (SAFE PIPES Act), was signed into law. The law prioritized the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) completion of outstanding regulations and proposed regulations to safety standards for natural gas transmission and gathering pipelines. The long-anticipated proposal could impose significant regulatory requirements for additional miles of natural gas pipeline, including pipelines constructed prior to 1970, which were previously exempt from PHMSA regulations related to pressure testing. It would also create a new "Moderate Consequence Area" category to expand safety protocols to pipelines in moderately populated areas. The rule also would codify the Integrity Verification Process (IVP) which is a process that will require companies to have reliable, traceable, verifiable, and complete records for pipelines in certain areas. The rule would establish a deadline for IVP completion that we will be required to meet. Costs incurred to comply with the proposed regulations may be material.

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, 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.

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.

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, both put downward pressure on load growth. Our resource plan includes an expected load growth assumption of 0.8 percent annually, 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 EIM 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.

Our plans for future expansion through the acquisition of assets including natural gas reserves, 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.

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 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

Our corporate support office is owned by us and located at 3010 West 69th Street, Sioux Falls, South Dakota 57108. Our operational support office for our Montana operations is owned by us and located at 11 East Park Street, Butte, Montana 59701. In addition, our operational support office for our South Dakota and Nebraska operations is owned by us and located at 600 Market Street West, Huron, South Dakota 57350. While we do lease some facilities, substantially all of our Montana, South Dakota and Nebraska facilities are owned by us.

Substantially all of our Montana electric and natural gas assets are subject to the lien of our Montana First Mortgage Bond indenture. Substantially all of our South Dakota and Nebraska electric and natural gas assets are subject to the lien of our South Dakota Mortgage Bond indenture. For further information regarding our operating properties, including generation and transmission, see the descriptions included in Item 1.

ITEM 3. LEGAL PROCEEDINGS

We discuss details of our legal proceedings in Note 19 - Commitments and Contingencies, to the Consolidated Financial Statements. Some of this information is about costs or potential costs that may be material to our financial results.

ITEM 4. MINE SAFETY DISCLOSURES

None

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

Our common stock, which is traded under the ticker symbol NWE, is listed on the New York Stock Exchange (NYSE). As of February 8, 2019, there were approximately 1,066 common stockholders of record.

Dividends

We pay dividends on our common stock after our Board declares them. The Board reviews the dividend quarterly and establishes the dividend rate based upon such factors as our earnings, financial condition, capital requirements, debt covenant requirements and/or other relevant conditions. Although we expect to continue to declare and pay cash dividends with a targeted long-term dividend payout ratio of 60 - 70 percent of earnings per share, we cannot assure that dividends will be paid in the future or that, if paid, the dividends will be paid in the same amount as during 2018.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data has been derived from our Consolidated Financial Statements and should be read in conjunction with the Consolidated Financial Statements and notes thereto and with “Management's Discussion and Analysis of Financial Condition and Results of Operations" and other financial data included elsewhere in this report. The historical results are not necessarily indicative of results to be expected for any future period.

FIVE-YEAR FINANCIAL SUMMARY

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Financial Results (in thousands, except per share data)					
Operating revenues	$ 1,192,009	1,305,652	$ 1,257,247	$ 1,214,299	$ 1,204,863
Net income	196,960	162,703	164,172	151,209	120,686
Basic earnings per share	$3.94	$3.35	$3.40	$3.20	$3.01
Diluted earnings per share	3.92	3.34	3.39	3.17	2.99
Dividends declared per common share	2.20	2.10	2.00	1.92	1.60
Financial Position					
Total assets	$ 5,644,376	5,420,917	$ 5,499,321	$ 5,264,695	$ 4,960,902
Total debt, including capital leases and short-term borrowings	2,124,558	2,137,318	2,120,474	2,026,219	1,946,790

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

The following discussion and analysis should be read in conjunction with “Item 6. Selected Financial Data" and our Consolidated Financial Statements and related notes contained elsewhere in this Annual Report on Form 10-K. For additional information related to our segments, see Note 21 - Segment and Related Information, to the Consolidated Financial Statements, which is included in Item 8 herein. For information regarding our revenues, net income and assets, see our Consolidated Financial Statements included in Item 8.

OVERVIEW

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 726,400 customers in Montana, South Dakota and Nebraska. As you read this discussion and analysis, refer to our Consolidated Statements of Income, which present the results of our operations for 2018, 2017 and 2016. Following is a discussion of our strategy and significant trends.

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

HOW WE PERFORMED IN 2018 COMPARED TO OUR 2017 RESULTS

	Year ended December 31,		
	2018	2017	Change, Net of Tax
		(in millions)	
Net Income	$ 197.0	$ 162.7	$ 34.3
Items increasing (decreasing) net income:			
QF liability adjustment			18.7
Impacts of Tax Cuts and Jobs Act			15.2
Electric transmission			4.6
Retail volumes			2.7
Labor			2.5
Depreciation and depletion			(6.2)
Hazard trees			(2.5)
Other			(0.7)
Change in net income			$ 34.3

Consolidated net income in 2018 was $197.0 million as compared with $162.7 million in 2017. This increase was primarily due to a gain related to the adjustment of our electric QF liability, the net impact of the Tax Cuts and Jobs Act, demand for electric transmission, favorable weather, and lower labor costs, partly offset by an increase in depreciation and depletion expense and an increase in expense associated with removing hazard trees outside of our electric transmission and distribution lines rights of way.

SIGNIFICANT TRENDS AND REGULATION

Montana General Electric Rate Case

In September 2018, we filed an electric rate case with the MPSC requesting an annual increase to electric rates of approximately $34.9 million, which represents an approximate 6.6% increase in annual base revenues. Our request is based on a return on equity of 10.65% and an overall rate of return of 7.42% (except for Colstrip Unit 4 which the MPSC previously set for the life of the facility at a 10% return on equity and an 8.25% rate of return), based on approximately $2.35 billion of electric rate base and a capital structure of 51 percent debt and 49 percent equity.

We also requested that approximately $13.8 million of the rate increase be approved on an interim basis effective November 1, 2018. We expect to receive a decision on our interim request after intervenor testimony is filed. If the MPSC does not issue a final order within nine months of the filing, the new requested rates may be placed into effect on an interim and refundable basis.

Key dates in the procedural schedule are expected to be as follows:

- Intervenor testimony - February 12, 2019
- NorthWestern rebuttal testimony and cross-intervenor testimony - April 5, 2019
- Hearing commences - May 13, 2019

We expect to file a FERC rate case for our Montana transmission assets by the end of the first quarter of 2019. The revenue requirement associated with our Montana FERC assets is reflected in our MPSC jurisdictional rates as a credit to customers.

Electric Resource Planning - Montana

In the first quarter of 2019, we expect to submit our draft 2019 Electricity Supply Resource Procurement Plan (Montana Resource Plan) with the MPSC. The Montana Resource Plan supports the goal of developing resources that will address the changing energy landscape in Montana to meet our customers' electric energy needs in a reliable and affordable manner. A summary of the draft Montana Resource Plan was provided for public comment in January 2019. After submission to the MPSC, the draft will be available for public comment for 60 days.

Montana is in the midst of a transition from producing more energy than is needed in the state with energy exported to the west, to a growing risk of not having enough capacity to serve Montana customers at critical times of peak load due to reductions in regional and in state energy generation as noted below:

- Our current peak requirement for energy is about 1,400 MW. We are currently 630 MW short, which is subject to market purchases. We forecast that our energy portfolio will be 725 MW short by 2025 with modest increased customer demand.
- Planned regional retirements of 3,500 MW of coal-fired generation are forecast by the Northwest Power and Conservation Council to cause regional peak energy shortages as early as 2021.

The long-term objective of the Montana Resource Plan is a clean, cost-effective, stable and reliable energy portfolio. Based on our customers' future energy resource needs as identified in 2019, we expect to solicit competitive proposals for up to 200 MW of peaking capacity available by 2022, which is about one-fourth of our projected need in 2025. An independent evaluator will be used to assess the proposals. We expect the process will be repeated in subsequent years to provide a resource-adequate energy and capacity portfolio. Using this staged approach, we propose to add 200 MWs of capacity per year from 2022 to 2025.

The proposal solicitation process will consider a wide variety of resource options and sizing, ownership options and contract lengths. This includes power purchase agreements and owned energy resources comprised of different structures, terms and technologies that are cost-effective resources. The staged approach is designed to allow for incremental steps through time with opportunities for different resource type of new technologies while also building a reliable portfolio to meet local and regional conditions and minimizing customer impacts.

Western Energy Imbalance Market

In November 2018, we announced our intent to enter the Western EIM, operated by the California ISO, in the spring of 2021. The Western EIM is intended to reduce the power supply costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability. Participation in the Western EIM is voluntary and available to all balancing authorities in the western United States. In order to participate in the Western EIM, we must demonstrate resource adequacy through a combination of owned or contracted resources.

Assumptions regarding entry into the Western EIM are incorporated into our Montana Resource Plan. In early 2018, the California ISO began a process to enhance the day-ahead market within the full Independent System Operator's footprint (the EDAM initiative). The enhancements to the day-ahead market are targeted to go live in 2019 with a platform that will allow the addition of a day-ahead market to the Western EIM. The extension of EDAM to EIM participants has not yet been formally introduced as a stakeholder process, but if current EIM members and the California ISO support moving forward, a stakeholder process will be initiated regarding the day-ahead EIM that could go live as early as 2022. Our Montana Resource Plan assumes that EIM entry will occur in 2021, followed by EDAM entry in 2022 and the development of a full market with an independent system operator in 2025.

Electric Resource Planning - South Dakota

Our 2018 South Dakota Electricity Supply Resource Procurement Plan (South Dakota Resource Plan) identified approximately 90MWs of existing generation that should be retired and replaced over the next 10 years with the goal of improving reliability and lowering operating costs. We expect to issue a request for proposal in the second quarter of 2019 to replace 60 MW of combustion turbine generation by December 2021, comparing the relative costs of the addition of a reciprocating internal combustion engine facility to other market offerings. In addition, we are currently installing 8 MW of mobile capacity generation, with units expected to be operational in the fourth quarter of 2019.

PURPA

PURPA requires us to purchase power from qualifying cogeneration and small power production facilities at a price approved by the MPSC that is meant to represent our “avoided cost” of generating power or purchasing power from another source. 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. Although the costs incurred to purchase power from QFs are passed on to customers, subject to the cost recovery mechanism discussed below, mandated purchases of QF generation, potentially at above-market prices, may reduce the need for new owned generation. This in turn could have a material adverse effect on our long-term capital investment plan and the affordability of future customer prices. We expect to establish a current avoided cost in Montana in conjunction with our Montana Resource Plan.

Colstrip

Colstrip Units 3 and 4 are supplied with fuel from adjacent coal reserves under coal supply and transportation agreements with WeCo in effect through 2019. WeCo filed for Chapter 11 bankruptcy protection in October 2018. An auction was held for the core assets in January 2019, including the mine adjacent to Colstrip, with no qualified bids received. As a result a lenders group is expected to acquire the core assets. During the course of the bankruptcy, WeCo may choose to assume or reject the existing coal supply and transportation agreements. WeCo indicated that it intends to reject the existing cost plus coal supply agreement. If WeCo rejects the existing agreement, the fuel supply to Units 3 and 4 may be interrupted until new arrangements are in place. In addition, any new arrangements may have higher costs than the existing cost plus agreement.

Hazard Trees

Hazard trees are those trees that are structurally unsound and could fall into our lines if the trees failed. Hazard trees may be located inside or outside our electric transmission and distribution lines' rights of way and pose risks to our system including disruption of service, property damage, loss of life, and/or fires. We are facing challenges to address these trees. Beetle infestations have caused a significant increase in the quantity of standing dead and dying timber and have impacted our system for quite some time. As part of our normal vegetation management program, we have routinely removed trees from within our rights of way, including those infected by the beetle infestation. Additionally, in some circumstances, we were authorized to remove one or more hazard trees from outside of our rights of way that could harm our system.

The beetle infestation exacerbates the risk of fires in Montana, increasing the risk that such trees may fall from either inside or outside our right-of-way into a powerline igniting a fire. Fires alleged to have been caused by our system could expose us to significant damage claims on theories such as strict liability, negligence, gross negligence, trespass, inverse condemnation, and others. We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We worked with third parties, including the U.S. Forest Service, to develop a plan to remove these hazard trees. We identified areas severely impacted and determined that the only way to mitigate fire and reliability risk along these lines is to clear-cut all of the trees on either side of the electric lines that could hit the lines, if they fell. In most cases, this results in a corridor of approximately 100 feet on either side of the lines. Normal rights of way vary but are generally 20 feet to 40 feet wide on distribution lines and 40 feet to 100 feet wide on transmission lines. We finalized our plan to address the identified areas in the first quarter of 2018 and began work.

- During 2018, we incurred approximately $3.3 million in costs related to this work, which is incremental to costs for vegetation management within our rights of way. We expect to continue the program over the next several years with anticipated 2019 costs ranging from approximately $7 million to $9 million, with total costs exceeding $20 million.

Tax Cuts and Jobs Act

In December 2017, the Tax Cuts and Jobs Act was signed into law, which enacts significant changes to U.S. tax and related laws. The primary impact to us is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. Dockets were opened in each of our jurisdictions to investigate the customer benefit of this reduction in the federal corporate income tax rate. During 2018, we received approval of settlement agreements regarding the customer benefit of the Tax Cuts and Jobs Act, as described below.

- In Montana the settlement provides a one-time credit of approximately $20.5 million to customers in early 2019. This includes a $19.2 million credit to electric customers and $1.3 million credit to natural gas customers.
    - In addition to eligible customers receiving a one-time bill credit, the settlement also reduces rates for all natural gas customers by approximately $1.3 million annually beginning January 1, 2019, and provides funds for low-income energy assistance and weatherization programs.
    - The settlement also reflects the agreement of the intervening parties not to oppose our request to include up to $3.5 million of costs to address hazard tree removal in our current Montana rate case.
    - Issues related to the revaluation of deferred income taxes will be addressed in our current Montana rate case.

- In South Dakota we credited electric and natural gas customers approximately $3.0 million in the fourth quarter of 2018, and agreed to a two-year rate moratorium until January 1, 2021.

Our 2018 results include a net benefit related to the impact of the Tax Cuts and Jobs Act, which includes:

- An income tax benefit of approximately $19.8 million due to the finalization of the revaluation of deferred income tax liabilities upon completion of the associated regulatory dockets; offset by
- A net loss of approximately $6.1 million including a reduction in revenue of approximately $23.5 million, due to customer credits in the above regulatory settlements, offset in part by a reduction in income tax expense, of approximately $17.4 million due to the reduction in federal tax rate.

In addition, we reflected the costs of our hazard tree program in the consolidated income statement as we agreed in our Montana settlement to request recovery of these costs in base customer rates in our 2018 filing, as discussed above, rather than using a portion of the reduction in customer rates associated with the change in tax rate as proposed in our Montana Tax Cuts and Jobs Act filing.

We expect a consolidated reduction in our cash flows from operations ranging from $20 million to $22 million in 2019, as a result of the customer credits discussed above while we are not a cash taxpayer. See Liquidity and Capital Resources for further discussion. We currently estimate that our effective income tax rate will range from 0% to 5% in 2019.

Cost Recovery Mechanisms

Electric Tracker - Effective July 1, 2017, the Montana legislature granted the MPSC discretion whether to approve an electric supply tracking mechanism. After considering our application in a contested case proceeding, the MPSC issued a final order in January 2019 approving a PCCAM with the following provisions:

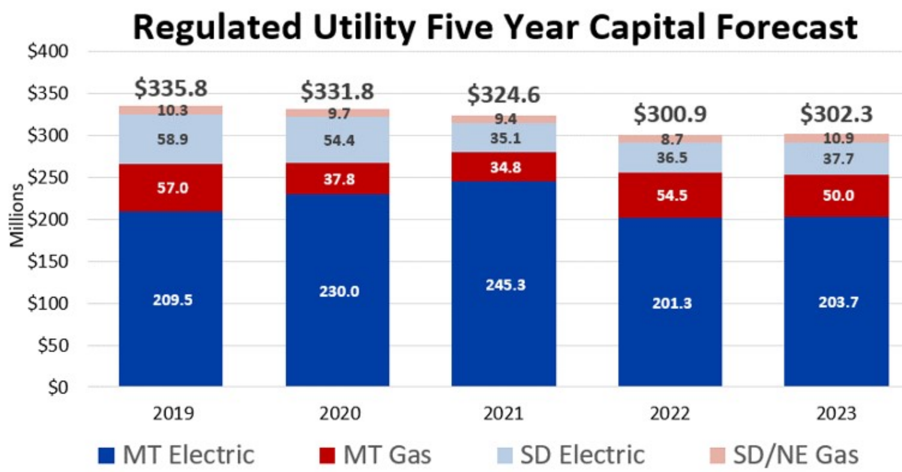
- A baseline of power supply costs;
- Annual adjustment of customer prices to reflect a portion of the difference between the established base revenues and actual costs, to the extent such difference is outside a +/- $4.1 million "deadband" from the base, with 90% of the variance above or below the deadband collected from or refunded to customers; and
- Retroactive implementation to the effective date of the new legislation (July 1, 2017).

Our 2018 results include a net reduction in the recovery of supply costs from customers of approximately $1.5 million in the Consolidated Statements of Income, which includes the following:

- For the 2017/2018 period, actual costs were below base revenues by approximately $3.4 million, resulting in no refund to customers.
- For the 2018/2019 period, actual costs were above base revenues by approximately $11.8 million, resulting in a regulatory asset for collection from customers of approximately $6.9 million as of December 31, 2018 and an approximately $4.9 million reduction in recovery of supply costs for the first six months of the period. For further discussion, see Results of Operations below.

INVESTMENT

Our estimated capital expenditures for the next five years, including our electric and natural gas transmission and distribution infrastructure investment plan, are as follows (in millions):



$ Millions	*2019*	*2020*	*2021*	*2022*	*2023*
Electric	$ 268.4	$ 284.4	$ 280.5	$ 237.8	$ 241.4
Naural Gas	67.4	47.4	44.1	63.1	60.9
Total Capital Forecast	$ 335.8	$ 331.8	$ 324.6	$ 300.9	$ 302.3

Distribution and Transmission Modernization and Maintenance - As part of our commitment to maintain high level reliability and system performance we continue to evaluate the condition of our distribution and transmission assets to address aging infrastructure through our asset management process. The primary goals of our infrastructure investment are to reverse the trend in aging infrastructure, maintain reliability, proactively manage safety, build capacity into the system, and prepare our network for the adoption of new technologies. We are taking a proactive and pragmatic approach to replace these assets while also evaluating the implementation of additional technologies to prepare the overall system for smart grid applications. We are currently installing Automated Metering Infrastructure (AMI) in our South Dakota and Nebraska jurisdictions. This project is expected to be completed in 2019 at a total cost of approximately $32 million. In Montana we are developing a similar AMI project to be started in 2020. While this project is still in the evaluation phase, we estimate our total AMI capital expenditures across all of our service territories to be in the range of approximately $100 to $110 million if fully deployed.

Electric Supply Resource Plans - Our energy resource plans discussed above identify portfolio resource requirements including potential investments. While our resource plans identify needs, any owned generation is subject to successful completion of the competitive solicitation process and are not reflected in the projections above. We anticipate that owned assets to address energy and capacity needs for both Montana and South Dakota could increase the capital forecast presented above in excess of $200 million over the next five years.

Natural Gas Production Assets - We own natural gas production and gathering system assets in Montana as a part of an overall strategy to provide rate stability and customer value through the addition of regulated assets that are not subject to market forces. Our estimated capital expenditure requirements above do not include estimates for incremental natural gas reserve acquisitions, potential peaking generation needs or other investment opportunities that may arise.

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 exclude (or include) 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 Consolidated Statements of Income.

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, and as a result do not typically impact operating or net income. In addition, Gross Margin is used by us to determine whether we are collecting the appropriate amount of energy costs from customers to allow 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

Year Ended December 31, 2018 Compared with Year Ended December 31, 2017

	Electric		Natural Gas		Total	
	2018	2017	2018	2017	2018	2017
	(in millions)					
Reconciliation of gross margin to operating revenue:						
Operating Revenues	$ 921.1	$1,037.1	$ 270.9	$ 268.6	$1,192.0	$1,305.7
Cost of Sales	194.6	334.0	78.3	76.3	272.9	410.3
Gross Margin(1)	**$ 726.5**	**$ 703.1**	**$ 192.6**	**$ 192.3**	**$ 919.1**	**$ 895.4**

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

	Year Ended December 31,			
	2018	2017	Change	% Change
	(in millions)			
Gross Margin				
Electric	$ 726.5	$ 703.1	$ 23.4	3.3 %
Natural Gas	192.6	192.3	0.3	0.2
Total Gross Margin(1)	**$ 919.1**	**$ 895.4**	**$ 23.7**	**2.6%**

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

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

	Gross Margin 2018 vs. 2017
Gross Margin Items Impacting Net Income	
Electric QF liability adjustment	$ 25.1
Electric transmission	6.2
Electric and natural gas retail volumes	3.6
Montana natural gas rates	0.4
Impacts of Tax Cuts and Jobs Act	(6.1)
PCCAM supply cost recovery	(1.5)
Other	2.3
Change in Gross Margin Impacting Net Income	**30.0**
Gross Margin Items Offset in Operating Expenses and Income Tax Expense	
Impacts of Tax Cuts and Jobs Act	(17.4)
Natural gas gathering fees	(0.5)
Natural gas production taxes	(0.4)
Property taxes recovered in trackers	11.7
Production tax credits flowed-through trackers	0.3
Change in Items Offset Within Net Income	**(6.3)**
Increase in Consolidated Gross Margin(1)	**$ 23.7**

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

Consolidated gross margin for items impacting net income increased $30.0 million, due to the following:

- A reduction in the electric QF liability due to the combination of (i) a periodic adjustment of the liability for price escalation, which was less than modeled resulting in a liability reduction of approximately $17.5 million; and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF related supply costs due to outages at two facilities;
- Higher demand to transmit energy across our transmission lines due to market conditions and pricing;
- An increase in electric and natural gas retail volumes due primarily to customer growth and favorable weather in South Dakota; and
- An increase in our Montana gas rates effective September 1, 2017.

These increases were partly offset by a $6.1 million reduction in revenue due to the impacts of the Tax Cuts and Jobs Act settlement and a $1.5 million reduction in recovery of Montana electric supply costs, as discussed above in Significant Trends and Regulation.

The change in consolidated gross margin also includes the following items that had no impact on net income:

- A reduction in revenue in 2018 to reflect the pass-through of the Tax Cuts and Job Act related benefits to customers, which is offset by a decrease in income tax expense;
- A decrease in natural gas gathering fees which are offset by reduced operating expenses;
- A decrease in natural gas production taxes which are offset by reduced property and other taxes;
- An increase in revenues for property taxes included in trackers, which are offset by increased property tax expense; and
- An increase in revenue due to decreased production tax credit benefits passed through to customers in our tracker mechanisms, which is offset by increased income tax expense.

	Year Ended December 31,			
	2018	2017	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 307.1	$ 294.8	$ 12.3	4.2 %
Property and other taxes	171.3	162.6	8.7	5.4
Depreciation and depletion	174.5	166.1	8.4	5.1
	$ 652.9	**$ 623.5**	**$ 29.4**	**4.7%**

Consolidated operating, general and administrative expenses were $307.1 million in 2018, as compared with $294.8 million in 2017. Primary components of the change include the following (in millions):

	Operating, General & Administrative Expenses 2018 vs. 2017
Operating, General & Administrative Expenses Impacting Net Income	
Employee benefits	$ 7.2
Hazard trees	3.3
Distribution System Infrastructure Project expenses	(3.7)
Labor	(3.3)
Maintenance costs	(2.6)
Other	1.2
Change in Items Impacting Net Income	**2.1**
Operating, General & Administrative Expenses Offset Within Net Income	
Pension and other postretirement benefits	10.3
Operating expenses recovered in trackers	1.1
Non-employee directors deferred compensation	(0.7)
Natural gas gathering fees	(0.5)
Change in Items Offset Within Net Income	**10.2**
Increase in Operating, General & Administrative Expenses	**$ 12.3**

Consolidated operating, general and administrative expenses for items impacting net income increased $2.1 million due to the following:

- An increase in employee benefit costs, primarily due to higher medical and employee incentive expense; and
- Costs incurred in 2018 to remove hazard trees outside of our electric transmission and distribution lines rights of way.

These increases were partly offset by the following:

- Lower expenses related to the Distribution System Infrastructure Project, which concluded in 2017;
- Decreased labor costs due primarily to fewer employees and more time being spent by employees on capital projects rather than maintenance projects (which are expensed); and
- Lower maintenance costs at electric generating facilities.

The change in consolidated operating, general and administrative expenses also includes the following items that had no impact on net income:

- The regulatory treatment of the non-service cost components of pension and postretirement benefit expense, which is offset in other income;
- Higher operating expenses included in trackers and recovered in revenue;
- A change in the value of non-employee directors deferred compensation due to the change in our stock price, which is offset in other income; and
- Lower gas gathering fees and production taxes, which is offset by lower margin discussed above.

Property and other taxes were $171.3 million in 2018, as compared with $162.6 million in 2017. This increase was primarily due to plant additions and higher estimated property valuations in Montana. Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover 74% of the increase in taxes and fees, which is net of the associated income tax benefit.

Depreciation and depletion expense was $174.5 million in 2018, as compared with $166.1 million in 2017. This increase was primarily due to plant additions.

Consolidated operating income in 2018 was $266.3 million as compared with $271.7 million in 2017. This decrease was primarily due to the overall increase in operating expenses, as discussed above, offset in part by higher gross margin.

Consolidated interest expense in 2018 was $92.0 million, as compared with $92.3 million in 2017. See "Liquidity and Capital Resources" for additional information regarding our financing activities.

Consolidated other income in 2018, was $4.0 million, as compared with consolidated other expense of $3.4 million in 2017. This increase includes a $10.3 million decrease in other pension expense (which is offset in operating, general, and administrative expenses), partly offset by lower capitalization of AFUDC.

Consolidated income tax benefit in 2018 was $18.7 million, as compared with consolidated income tax expense of $13.4 million in 2017. Our effective tax rate for the twelve months ended December 31, 2018 was (10.5)% as compared with 7.6% for the same period of 2017. The decrease in income tax expense in 2018 is primarily due to the impact of the lower federal tax rate and a benefit of approximately $19.8 million associated with the final measurement of excess deferred taxes.

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

	Year Ended December 31,			
	2018		2017	
Income Before Income Taxes	$ 178.3		$ 176.1	
Income tax calculated at federal statutory rate	37.4	21.0 %	61.6	35.0%
Permanent or flow through adjustments:				
State income, net of federal provisions	1.6	0.9	(3.3)	(1.9)
Impact of Tax Cuts and Jobs Act	(19.8)	(11.1)	—	—
Flow-through repairs deductions	(19.3)	(10.8)	(30.5)	(17.3)
Production tax credits	(10.9)	(6.1)	(11.0)	(6.3)
Prior year permanent return to accrual adjustments	(3.0)	(1.7)	(0.6)	(0.3)
Plant and depreciation of flow through items	(2.2)	(1.2)	(2.2)	(1.3)
Share-based compensation	0.2	0.1	(0.4)	(0.2)
Other, net	(2.7)	(1.6)	(0.2)	(0.1)
	(56.1)	(31.5)	(48.2)	(27.4)
Income Tax (Benefit) Expense	$ (18.7)	(10.5)%	$ 13.4	7.6%

Consolidated net income in 2018 was $197.0 million as compared with $162.7 million in 2017. This increase was primarily due to a gain related to the adjustment of our electric QF liability, demand for electric transmission, customer growth and favorable weather, and an income tax benefit associated with the impacts of the Tax Cuts and Jobs Act, partly offset by an increase in depreciation expense.

Year Ended December 31, 2017 Compared with Year Ended December 31, 2016

	Electric		Natural Gas		Total	
	2017	2016	2017	2016	2017	2016
	(in millions)					
Reconciliation of gross margin to operating revenue:						
Operating Revenues	$1,037.1	$1,011.6	$ 268.6	$ 245.7	$1,305.7	$1,257.3
Cost of Sales	334.0	332.8	76.3	68.2	410.3	401.0
Gross Margin[1]	**$ 703.1**	**$ 678.8**	**$ 192.3**	**$ 177.5**	**$ 895.4**	**$ 856.3**

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

	Year Ended December 31,			
	2017	2016	Change	% Change
	(in millions)			
Gross Margin				
Electric	$ 703.1	$ 678.8	$ 24.3	3.6%
Natural Gas	192.3	177.5	14.8	8.3
Total Gross Margin[1]	$ 895.4	$ 856.3	$ 39.1	4.6%

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

Consolidated gross margin in 2017 was $895.4 million, an increase of $39.1 million, or 4.6%, from gross margin in 2016. Factors that impacted gross margin included (in millions):

	Gross Margin 2017 vs. 2016
Gross Margin Items Impacting Net Income	
Electric retail volumes	$ 15.7
Natural gas retail volumes	10.5
2016 MPSC disallowance	9.5
Montana natural gas rates	1.8
2016 Hydro generation rates	1.5
South Dakota electric rate increase	1.2
Electric transmission	0.6
Electric QF adjustment	0.4
2016 Lost revenue adjustment mechanism	(14.2)
Other	3.9
Consolidated Gross Margin Impacting Net Income	**30.9**
Gross Margin Items Offset within Net Income	
Property taxes recovered in trackers	6.7
Operating expenses recovered in trackers	1.5
Change in Items Offset Within Net Income	**8.2**
Increase in Consolidated Gross Margin[1]	**$ 39.1**

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

Consolidated gross margin for items impacting net income increased $30.9 million primarily due to the following:

- An increase in electric retail volumes due primarily to colder winter and warmer summer weather in our Montana jurisdiction and customer growth, partly offset by cooler summer weather in our South Dakota jurisdiction and milder spring weather overall;

- An increase in natural gas retail volumes due primarily to colder winter and spring weather and customer growth, partly offset by warmer summer weather;
- The inclusion in our 2016 results of the MPSC disallowance of both replacement power costs from a 2013 outage at Colstrip Unit 4 and portfolio modeling costs;
- An increase in our Montana gas rates effective September 1, 2017;
- The inclusion in our 2016 results of a reduction in hydro generation rates due to the MPSC order in the hydro compliance filing;
- An increase in South Dakota electric rates due to the timing of the change in customer rates in 2016;
- Higher demand to transmit energy across our transmission lines due to market conditions and pricing; and
- A decrease in QF related supply costs based on actual QF pricing and output.

These increases were partly offset by the inclusion in our 2016 results of $14.2 million of deferred revenue as a result of a MPSC final order in our tracker filings regarding prior period lost revenues.

The change in consolidated gross margin also includes the following items that had no impact on net income:

- An increase in revenues for property taxes included in trackers is offset by increased property tax expense; and
- An increase in operating expenses included in our supply trackers is offset by an increase in operating, general and administrative expenses.

	Year Ended December 31,			
	2017	**2016**	**Change**	**% Change**
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 294.8	$ 293.9	$ 0.9	0.3%
Property and other taxes	162.6	148.1	14.5	9.8
Depreciation and depletion	166.1	159.3	6.8	4.3
	$ 623.5	$ 601.3	$ 22.2	3.7%

Consolidated operating, general and administrative expenses were $294.8 million in 2017 as compared with $293.9 million in 2016. Primary components of this change include the following (in millions):

	Operating, General, & Administrative Expenses 2017 vs. 2016
Operating, General & Administrative Expenses Impacting Net Income	
Bad debt expense	$ 1.9
Maintenance costs	1.2
Employee benefits and compensation costs	(1.5)
Insurance reserves	(1.0)
Other	0.1
Change in Items Impacting Net Income	0.7
Operating, General & Administrative Expenses Offset Within Net Income	
Operating expenses recovered in trackers	1.5
Pension and other postretirement benefits	(1.3)
Change in Items Offset Within Net Income	0.2
Increase in Operating, General & Administrative Expenses	**$ 0.9**

Consolidated operating, general and administrative expenses for items impacting net income increased $0.7 million primarily due to the following:

- Higher bad debt expense due to an increase in revenues as a result of colder winter and warmer summer weather; and
- Higher maintenance costs at our Dave Gates Generating Station and Colstrip Unit 4.

These increases were offset in part by:

- A decrease in employee benefits due primarily to lower pension costs, offset in part by higher medical costs and more time spent by employees on maintenance projects (which are expensed) rather than capital projects; and
- A decrease in insurance reserves primarily due to the amount recorded in 2016 related to the Billings, Montana refinery outage.

The change in consolidated operating, general and administrative expenses also includes the following items that had no impact on net income:

- Higher operating expenses recovered through our supply trackers; and
- The regulatory treatment of the non-service cost component of pension and postretirement benefit expense, offset in other income.

Property and other taxes were $162.6 million in 2017 as compared with $148.1 million in 2016. This increase was primarily due to plant additions and higher estimated property valuations in Montana.

Depreciation and depletion expense was $166.1 million in 2017 as compared with $159.3 million in 2016. This increase was primarily due to plant additions.

Consolidated operating income in 2017 was $271.7 million, as compared with $255.0 million in 2016. This increase was primarily due to the increase in gross margin as discussed above, offset in part by higher operating expenses.

Consolidated interest expense in 2017 was $92.3 million, as compared with $95.0 million, in 2016. This decrease was primarily due to the refinancing of debt in 2016. See "Liquidity and Capital Resources" for additional information regarding our financing activities.

Consolidated other income in 2017 was $3.4 million as compared with $3.5 million in 2016. This decrease was primarily due to an increase in other pension expense, offset in part by higher capitalization of AFUDC.

Consolidated income tax expense in 2017 was $13.4 million as compared with an income tax benefit of $7.6 million in 2016. Our effective tax rate for the twelve months ended December 31, 2017 was 7.6% as compared with (4.9)% for the same period of 2016. During the twelve months ended December 31, 2016, we recorded an income tax benefit of approximately $17.0 million due to the adoption of a tax accounting method change related to the costs to repair generation assets, which allowed us to take a current tax deduction for a significant amount of repair costs that were previously capitalized for tax purposes. Approximately $12.5 million of this deduction related to 2015 and prior tax years. This is reflected in the flow-through repairs deductions line due to the regulatory treatment.

Our effective tax rate typically differs from the federal statutory tax rate primarily 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 following table summarizes the differences between our effective tax rate and the federal statutory rate (in millions):

	Year Ended December 31,			
	2017		2016	
Income Before Income Taxes	$ 176.1		$ 156.5	
Income tax calculated at 35% Federal statutory rate	61.6	35.0%	54.8	35.0 %
Permanent or flow through adjustments:				
State income tax, net of federal provisions	(3.3)	(1.9)	(3.7)	(2.4)
Flow through repairs deductions	(30.5)	(17.3)	(41.1)	(26.3)
Production tax credits	(11.0)	(6.3)	(10.9)	(7.0)
Plant and depreciation of flow through items	(2.2)	(1.3)	(4.6)	(2.9)
Share based compensation	(0.4)	(0.2)	(1.6)	(1.1)
Prior year permanent return to accrual adjustments	(0.6)	(0.3)	(0.1)	(0.1)
Other, net	(0.2)	(0.1)	(0.4)	(0.1)
	(48.2)	(27.4)	(62.4)	(39.9)
Income Tax Expense (Benefit)	$ 13.4	7.6%	$ (7.6)	(4.9)%

Consolidated net income in 2017 was $162.7 million as compared with $164.2 million in 2016. This decrease was primarily due to the inclusion in our 2016 results of a $17.0 million income tax benefit due to the adoption of a tax accounting method change related to the costs to repair generation assets, and higher operating expenses as discussed above, offset in part by improved gross margin as a result of favorable weather, and to a lesser extent, by customer growth.

ELECTRIC OPERATIONS

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.

Year Ended December 31, 2018 Compared with Year Ended December 31, 2017

	Results			
	2018	2017	Change	% Change
	(in millions)			
Retail revenue	$ 847.3	$ 874.4	$ (27.1)	(3.1)%
Regulatory amortization	9.8	3.7	6.1	(164.9)
Total retail revenues	857.1	878.1	(21.0)	(2.4)
Transmission	58.1	59.7	(1.6)	(2.7)
Wholesale and Other	5.9	99.3	(93.4)	(94.1)
Total Revenues	**921.1**	**1,037.1**	**(116.0)**	**(11.2)**
Total Cost of Sales	**194.6**	**334.0**	**(139.4)**	**(41.7)**
Gross Margin[(1)]	**$ 726.5**	**$ 703.1**	**$ 23.4**	**3.3 %**

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

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2018	2017	2018	2017	2018	2017
	(in thousands)					
Montana	$ 287,358	$ 299,725	2,518	2,540	299,438	295,427
South Dakota	64,171	60,246	598	546	50,546	50,247
Residential	**351,529**	**359,971**	**3,116**	**3,086**	**349,984**	**345,674**
Montana	329,611	348,139	3,169	3,235	67,547	66,484
South Dakota	93,992	91,969	1,072	992	12,741	12,669
Commercial	**423,603**	**440,108**	**4,241**	**4,227**	**80,288**	**79,153**
Industrial	42,577	42,194	2,593	2,324	75	75
Other	29,600	32,110	166	195	6,185	6,195
Total Retail Electric	**$ 847,309**	**$ 874,383**	**10,116**	**9,832**	**436,532**	**431,097**

	Cooling Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	337	524	409	36% colder	18% colder
South Dakota	951	729	733	30% warmer	30% warmer

	Heating Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	7,882	7,738	7,529	2% colder	5% colder
South Dakota	8,385	7,102	7,752	18% colder	8% colder

The following summarizes the components of the changes in electric gross margin for the year ended December 31, 2018 and 2017 (in millions):

	Gross Margin 2018 vs. 2017	
Gross Margin Items Impacting Net Income		
QF liability adjustment	$	25.1
Transmission		6.2
Retail volumes		0.3
Impacts of Tax Cuts and Jobs Act		(8.6)
PCCAM supply cost recovery		(1.5)
Other		3.5
Change in Gross Margin Impacting Net Income		**25.0**
Gross Margin Items Offset Within Net Income		
Impacts of Tax Cuts and Jobs Act		(12.9)
Property taxes recovered in trackers		11.0
Production tax credits flowed-through trackers		0.3
Change in Items Offset Within Net Income		**(1.6)**
Increase in Gross Margin[(1)]	**$**	**23.4**

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

Gross margin for items impacting net income increased $25.0 million including the following:

- A reduction in the QF liability due to the combination of (i) a periodic adjustment of the liability for price escalation, which was less than modeled resulting in a liability reduction of approximately $17.5 million; and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF related supply costs due to outages at two facilities;
- Higher demand to transmit energy across our transmission lines due to market conditions and pricing; and
- An increase in retail volumes due primarily to customer growth and favorable weather in our South Dakota jurisdiction, partly offset by unfavorable weather in our Montana jurisdiction.

These increases were partly offset by an $8.6 million decrease from the Tax Cuts and Jobs Act settlement and a $1.5 million reduction in recovery of energy supply costs associated with the Montana PCCAM, as discussed above.

The change in gross margin also includes the following items that had no impact on net income:

- A reduction in revenue in 2018 to reflect the pass-through of the Tax Cuts and Job Act related benefits to customers, which are offset in part by a decrease in income tax expense;
- An increase in revenues for property taxes included in trackers, which are offset by increased property tax expense; and
- An increase in revenue due to the decrease in production tax credit benefits passed through to customers in our tracker mechanisms, which is offset by an increase in income tax expense.

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.

Year Ended December 31, 2017 Compared with Year Ended December 31, 2016

	Results			
	2017	2016	Change	% Change
	(in millions)			
Retail revenue	$ 874.4	$ 840.7	$ 33.7	4.0 %
Regulatory amortization	3.7	20.9	(17.2)	(82.3)
Total retail revenues	878.1	861.6	16.5	1.9
Transmission	59.7	52.7	7.0	13.3
Wholesale and other	99.3	97.3	2.0	2.1
Total Revenues	**1,037.1**	**1,011.6**	**25.5**	**2.5**
Total Cost of Sales	**334.0**	**332.8**	**1.2**	**0.4%**
Gross Margin[(1)]	**$ 703.1**	**$ 678.8**	**$ 24.3**	**3.6%**

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

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2017	2016	2017	2016	2017	2016
	(in thousands)					
Montana	$ 299,725	$ 280,379	2,540	2,372	295,427	291,348
South Dakota	60,246	57,369	546	548	50,247	50,016
Residential	**359,971**	**337,748**	**3,086**	**2,920**	**345,674**	**341,364**
Montana	348,139	343,982	3,235	3,177	66,484	65,568
South Dakota	91,969	87,199	992	985	12,669	12,591
Commercial	**440,108**	**431,181**	**4,227**	**4,162**	**79,153**	**78,159**
Industrial	42,194	40,577	2,324	2,204	75	74
Other	32,110	31,162	195	188	6,195	6,143
Total Retail Electric	**$ 874,383**	**$ 840,668**	**9,832**	**9,474**	**431,097**	**425,740**

	Cooling Degree Days			2017 as compared with:	
	2017	2016	Historic Average	2016	Historic Average
Montana	524	367	420	43% warmer	25% warmer
South Dakota	729	895	733	19% colder	1% colder

	Heating Degree Days			2017 as compared with:	
	2017	2016	Historic Average	2016	Historic Average
Montana	7,738	7,011	7,476	10% colder	4% colder
South Dakota	7,102	6,593	7,619	8% colder	7% warmer

The following summarizes the components of the changes in electric margin for the years ended December 31, 2017 and 2016 (in millions):

		Gross Margin 2017 vs. 2016
Gross Margin Items Impacting Net Income		
Retail volumes	$	15.7
2016 MPSC disallowance		9.5
2016 Hydro generation rates		1.5
South Dakota rate increase		1.2
Transmission		0.6
QF adjustment		0.4
2016 Lost revenue adjustment mechanism		(13.4)
Other		2.4
Change in Gross Margin Impacting Net Income		**17.9**
Gross Margin Items Offset Within Net Income		
Property taxes recovered in trackers		4.9
Operating expenses recovered in trackers		1.5
Change in Items Offset Within Net Income		**6.4**
Increase in Gross Margin (1)	**$**	**24.3**

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

Gross margin for items impacting net income increased $17.9 million including the following:

- An increase in retail volumes due primarily to colder winter and warmer summer weather in our Montana jurisdiction and customer growth, partly offset by cooler summer weather in our South Dakota jurisdiction and milder spring weather overall;
- The inclusion in our 2016 results of the MPSC disallowance of both replacement power costs from a 2013 outage at Colstrip Unit 4 and portfolio modeling costs;
- The inclusion in our 2016 results of a reduction in hydro generation rates due to the MPSC order in the hydro compliance filing;
- An increase in South Dakota electric rates due to the timing of the change in customer rates in 2016;
- Higher demand to transmit energy across our transmission lines due to market conditions and pricing; and
- A decrease in QF related supply costs based on actual QF pricing and output.

These increases were partly offset by the recognition in 2016 of $13.4 million of deferred revenue as a result of a MPSC final order in our tracker filings.

The change in consolidated gross margin also includes the following items that had no impact on net income:

- The increase in revenues for property taxes included in trackers is offset by increased property tax expense; and
- An increase in operating expenses included in our supply trackers is offset by an increase in operating, general and administrative expenses.

NATURAL GAS OPERATIONS

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.

Year Ended December 31, 2018 Compared with Year Ended December 31, 2017

	Results			
	2018	2017	Change	% Change
	(in millions)			
Retail revenues	$ 235.3	$ 233.8	$ 1.5	0.6 %
Regulatory amortization	(4.2)	(5.4)	1.2	22.2
Total retail revenues	231.1	228.4	2.7	1.2
Wholesale and other	39.8	40.2	(0.4)	(1.0)
Total Revenues	**270.9**	**268.6**	**2.3**	**0.9**
Total Cost of Sales	**78.3**	**76.3**	**2.0**	**2.6**
Gross Margin[(1)]	**$ 192.6**	**$ 192.3**	**$ 0.3**	**0.2%**

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

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2018	2017	2018	2017	2018	2017
	(in thousands)					
Montana	$ 102,721	$ 108,949	13,818	13,782	172,770	170,561
South Dakota	25,359	21,777	3,296	2,768	39,742	39,561
Nebraska	23,416	20,135	2,834	2,359	37,356	37,289
Residential	**151,496**	**150,861**	**19,948**	**18,909**	**249,868**	**247,411**
Montana	51,700	54,729	7,288	7,230	23,877	23,537
South Dakota	17,984	15,706	3,348	2,873	6,689	6,573
Nebraska	11,953	10,433	2,054	1,759	4,833	4,783
Commercial	**81,637**	**80,868**	**12,690**	**11,862**	**35,399**	**34,893**
Industrial	1,159	1,119	171	152	244	253
Other	986	958	156	141	163	159
Total Retail Gas	**$ 235,278**	**$ 233,806**	**32,965**	**31,064**	**285,674**	**282,716**

	Heating Degree Days			2018 as compared with:	
	2018	2017	Historic Average	2017	Historic Average
Montana	7,978	8,001	7,761	0% warmer	3% colder
South Dakota	8,385	7,102	7,752	18% colder	8% colder
Nebraska	6,792	5,551	6,402	22% colder	6% colder

The following summarizes the components of the changes in natural gas gross margin for the years ended December 31, 2018 and 2017 (in millions):

		Gross Margin 2018 vs. 2017
Gross Margin Items Impacting Net Income		
Retail volumes	$	3.3
Impacts of Tax Cuts and Jobs Act		2.5
Montana rates		0.4
Other		(1.2)
Change in Gross Margin Impacting Net Income		5.0
Gross Margin Items Offset Within Net Income		
Impacts of Tax Cuts and Jobs Act		(4.5)
Production gathering fees		(0.5)
Production taxes		(0.4)
Property taxes recovered in trackers		0.7
Change in Items Offset Within Net Income		(4.7)
Increase in Gross Margin[(1)]	**$**	**0.3**

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

Gross margin for items impacting net income increased $5.0 million including the following:

- An increase in retail volumes due primarily to favorable weather in South Dakota and customer growth;
- An increase from the Tax Cuts and Jobs Act settlement as discussed above; and
- An increase in our Montana rates effective September 1, 2017.

The change in gross margin also includes the following items that had no impact on net income:

- A decrease due to the deferral of revenue as a result of the Tax Cuts and Job Act, which is offset by a decrease in income tax expense;
- A decrease in gathering fees, which are offset by reduced operating expenses;
- A decrease in production tax revenue, which is offset by reduced property and other taxes; and
- An increase in revenues for property taxes included in trackers, which are offset by increased property tax expense.

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

Year Ended December 31, 2017 Compared with Year Ended December 31, 2016

	Results			
	2017	2016	Change	% Change
	(in millions)			
Retail revenue	$ 233.8	$ 201.8	$ 32.0	15.9 %
Regulatory amortization	(5.4)	4.8	(10.2)	(212.5)
Total retail revenues	228.4	206.6	21.8	10.6
Wholesale and other	40.2	39.1	1.1	2.8
Total Revenues	**268.6**	**245.7**	**22.9**	**9.3**
Total Cost of Sales	**76.3**	**68.2**	**8.1**	**11.9**
Gross Margin[(1)]	**$ 192.3**	**$ 177.5**	**$ 14.8**	**8.3%**

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

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2017	2016	2017	2016	2017	2016
	(in thousands)					
Montana	$ 108,949	$ 93,034	13,782	12,178	170,561	168,220
South Dakota	21,777	20,399	2,768	2,533	39,561	39,207
Nebraska	20,135	17,043	2,359	2,179	37,289	37,129
Residential	**150,861**	**130,476**	**18,909**	**16,890**	**247,411**	**244,556**
Montana	54,729	46,515	7,230	6,343	23,537	23,223
South Dakota	15,706	14,051	2,873	2,665	6,573	6,456
Nebraska	10,433	8,858	1,759	1,689	4,783	4,725
Commercial	**80,868**	**69,424**	**11,862**	**10,697**	**34,893**	**34,404**
Industrial	1,119	1,031	152	147	253	259
Other	958	888	141	137	159	157
Total Retail Gas	**$ 233,806**	**$ 201,819**	**31,064**	**27,871**	**282,716**	**279,376**

	Heating Degree Days			2017 as compared with:	
	2017	2016	Historic Average	2016	Historic Average
Montana	8,001	7,300	7,792	10% colder	3% colder
South Dakota	7,102	6,593	7,619	8% colder	7% warmer
Nebraska	5,551	5,322	6,289	4% colder	12% warmer

The following summarizes the components of the changes in natural gas margin for the years ended December 31, 2017 and 2016 (in millions):

	Gross Margin 2017 vs. 2016
Gross Margin Items Impacting Net Income	
Retail volumes	$ 10.5
Montana rates	1.8
Lost revenue adjustment mechanism	(0.8)
Other	1.5
Change in Gross Margin Impacting Net Income	**13.0**
Gross Margin Items Offset Within Net Income	
Property taxes recovered in trackers	1.8
Change in Items Offset Within Net Income	**1.8**
Increase in Gross Margin[(1)]	**$ 14.8**

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

Gross margin for items impacting net income increased $13.0 million including the following:

- An increase in retail volumes from colder winter and spring weather and customer growth, partly offset by warmer summer weather; and
- An increase in our Montana gas rates effective September 1, 2017.

These increases were partly offset by the recognition in 2016 of $0.8 million of deferred revenue as a result of an MPSC final order in our tracker filings. The increase in revenues for property taxes included in trackers is offset by increased property tax expense with no impact to net income.

LIQUIDITY AND CAPITAL RESOURCES

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 and existing borrowing capacity 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.

Liquidity is provided by internal cash flows and the use of our unsecured revolving credit facility. We have a $400 million revolving credit facility. In addition, on March 27, 2018, we entered into a $25 million revolving credit facility, maturing March 27, 2020, to provide swingline borrowing capability. We utilize availability under our revolvers 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 December 31, 2018, our total net liquidity was approximately $124.7 million, including $7.9 million of cash and $116.8 million of revolving credit facility availability. As of December 31, 2018, there was $0.2 million of letters of credit outstanding and $308 million in borrowings under our revolving line of credit. As of February 8, 2019, our availability under our revolving credit facility was approximately $132.8 million.

We issue debt securities to refinance retiring maturities, reduce revolver debt, 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 allows us to maintain investment grade ratings.

In September 2017, we entered into an Equity Distribution Agreement with Merrill Lynch, Pierce, Fenner, & Smith, Incorporated and J. P. Morgan Securities LLC, collectively the sales agents, pursuant to which we offered and sold shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. We concluded this program during the second quarter of 2018. During 2018, we issued 835,765 shares of our common stock at an average price of $54.45, for net proceeds of $44.9 million. Since inception of the program, we sold 1,724,703 shares of our common stock at an average price of $57.98 per share. Net proceeds received were approximately $98.5 million, which are net of sales commissions and other fees paid of approximately $1.4 million.

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

The Tax Cuts and Jobs Act lowered the corporate federal income tax rate from 35 percent to 21 percent and eliminated bonus depreciation for regulated utilities. This reduction in federal income taxes results in lower regulated customer rates as discussed above in Significant Trends and Regulation. However, due to the lower federal corporate income tax rate enacted by the Tax Cuts and Jobs Act, our future federal corporate income tax payments will also be reduced. Due to our existing Net Operating Loss (NOL) position and other tax credits, we expect to be a federal cash tax payer during 2020, with credits reducing our cash tax obligation into 2022. The reduction in revenues collected from customers is expected to negatively impact our 2019 cash flows from operations by approximately $20 million to $22 million.

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 Standard and Poor's Ratings Service (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 February 8, 2019, our current ratings with these agencies are as follows:

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

(1) In February 2018, Fitch affirmed our ratings, but revised our outlook from stable to negative citing continued regulatory headwinds in Montana and expected weakness in leverage metrics through 2021. Fitch also indicated that an adverse outcome in either our Montana electric supply tracker docket or our electric general rate case would likely result in a one-notch downgrade.

(2) In May 2018, Moody's downgraded our senior secured rating to A3 from A2, and our unsecured credit rating to Baa2 from Baa1 and revised our outlook from negative to stable. Moody's cited an extended period of weak financial metrics and challenging regulatory relationship in Montana as reasons for the downgrade.

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.

Capital Requirements

Our capital expenditures program is subject to continuing review and modification. Actual utility construction expenditures may vary from estimates due to changes in electric and natural gas projected load growth, changing business operating conditions and other business factors. We anticipate funding capital expenditures through cash flows from operations, available credit sources, debt and equity issuances and future rate increases. Our estimated capital expenditures are discussed above in the "Investment" section.

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 December 31, 2018. See additional discussion in Note 19 – Commitments and Contingencies to the Consolidated Financial Statements.

	Total	2019	2020	2021	2022	2023	Thereafter
				(in thousands)			
Long-term debt (1)	$ 2,114,637	$ —	$ 18,000	$ 290,000	$ —	$ —	$ 1,806,637
Capital leases	22,213	2,298	2,476	2,668	2,875	3,097	8,799
Estimated pension and other postretirement obligations (2)	60,803	12,471	12,199	12,214	12,046	11,873	N/A
Qualifying facilities (3) liability	709,795	75,278	77,319	79,166	81,060	83,178	313,794
Supply and capacity contracts (4)	2,060,466	197,036	149,601	124,292	126,873	122,093	1,340,571
Contractual interest payments on debt (5)	1,509,485	81,549	81,549	80,956	71,632	71,632	1,122,167
Environmental remediation obligations (2)	3,700	1,100	1,200	1,000	200	200	N/A
Total Commitments (6)	$ 6,481,099	$ 369,732	$ 342,344	$ 590,296	$ 294,686	$ 292,073	$ 4,591,968

(1) Represents cash payments for long-term debt and excludes $12.3 million of debt discounts and debt issuance costs, net.
(2) We have estimated cash obligations related to our pension and other postretirement benefit programs and environmental remediation obligations for five years, as it is not practicable to estimate thereafter. The pension and other 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 $709.8 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $567.2 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 25 years.
(5) Contractual interest payments includes our revolving credit facilities, which have a variable interest rate. We have assumed an average interest rate of 3.76% on the outstanding balance through maturity of the facilities.
(6) Potential tax payments related to uncertain tax positions are not practicable to estimate and have been excluded from this table.

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 the market prices of our electric and natural gas supply, which is currently recovered through various monthly cost tracking mechanisms. These energy supply tracking mechanisms are designed to provide stable and timely recovery of supply costs on a monthly basis during the July to June annual tracking period, with an adjustment in the following annual tracking period to correct for any under or over collection in our monthly trackers. 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 usually 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. In 2017, a Montana statute that provided for mandatory recovery of our prudently incurred electric supply costs was amended, and that statute now gives the MPSC discretion as to whether to approve electric supply costs. In the third quarter of 2018, the MPSC voted to approve a mechanism for recovery of electric supply costs that includes a sharing of costs beyond a specified deadband above or below baseline costs, which may impact our cash flows. See Note 4 - Regulatory Matters, for further discussion of this docket.

As of December 31, 2018, we are over collected on our natural gas and electric trackers by approximately $1.5 million, as compared with under collections of $13.2 million as of December 31, 2017, and $11.7 million as of December 31, 2016.

Cash Flows

The following table summarizes our consolidated cash flows for 2018, 2017 and 2016 (in millions):

	Year Ended December 31,		
	2018	2017	2016
Operating Activities			
Net income	$ 197.0	$ 162.7	$ 164.2
Non-cash adjustments to net income	169.5	182.7	155.4
Changes in working capital	51.8	(15.3)	(27.3)
Other noncurrent assets and liabilities	(36.3)	(7.4)	(5.5)
	382.0	**322.7**	**286.8**
Investing Activities			
Property, plant and equipment additions	(284.0)	(276.4)	(287.9)
Acquisitions	(18.5)	—	—
Proceeds from sale of assets	0.1	0.4	1.4
Investment in equity securities	(2.5)	—	—
	(304.9)	**(276.0)**	**(286.5)**
Financing Activities			
Proceeds from issuance of common stock, net	44.8	53.7	—
Issuances of long-term debt, net	—	—	24.5
Line of credit borrowings, net	308.0	—	—
(Repayments) issuances of short-term borrowings, net	(319.6)	18.7	70.9
Dividends on common stock	(109.2)	(101.3)	(95.8)
Financing costs	(0.1)	(16.4)	(8.4)
Other	2.3	1.1	(0.6)
	(73.8)	**(44.2)**	**(9.4)**
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	**$ 3.3**	**$ 2.5**	**$ (9.1)**
Cash, Cash Equivalents, and Restricted Cash, beginning of period	$ 12.0	$ 9.5	$ 18.6
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 15.3**	**$ 12.0**	**$ 9.5**

Cash Flows Provided By Operating Activities

As of December 31, 2018, our cash, cash equivalents, and restricted cash were $15.3 million as compared with $12.0 million at December 31, 2017. Cash provided by operating activities totaled $382.0 million for the year ended December 31, 2018 as compared with $322.7 million during 2017. This increase in operating cash flows is primarily due to higher net income, improved customer receipts, and the receipt of insurance proceeds during the current period.

Our 2017 operating cash flows increased by approximately $35.9 million as compared with 2016. This increase in operating cash flows is primarily due to customer refunds in 2016 associated with the DGGS FERC ruling and interim rates in our South Dakota electric rate case of approximately $30.8 million and $7.2 million, respectively, and to higher net income after non-cash adjustments during 2017.

Cash Flows Used In Investing Activities

Cash used in investing activities totaled $304.9 million during the year ended December 31, 2018, as compared with $276.0 million during 2017, and $286.5 million in 2016. Plant additions during 2018 include maintenance additions of approximately $227.0 million, capacity related capital expenditures of approximately $57.0 million, and the acquisition of the 9.7 MW Two Dot wind project in Montana for approximately $18.5 million. Plant additions during 2017 include maintenance additions of approximately $161.9 million, capacity related capital expenditures of approximately $77.3 million, and infrastructure capital expenditures of approximately $37.2 million. Plant additions during 2016 include maintenance additions of approximately $158.6 million, capacity related capital expenditures of approximately $79.0 million, and infrastructure capital expenditures of approximately $50.3 million.

Cash Flows Used in Financing Activities

Cash used in financing activities totaled $73.8 million during 2018 as compared to $44.2 million during 2017 and $9.4 million during 2016. During 2018, net cash used in financing activities reflects net repayments of commercial paper of $319.6 million and the payments of dividends of $109.2 million, partially offset by net issuances under our revolving lines of credit of $308.0 million and proceeds from the issuance of common stock of $44.8 million. During 2017, net cash used in financing activities includes the payment of dividends of $101.3 million and the payment of financing costs of $16.4 million, partially offset by proceeds from the issuance of common stock of $53.7 million and net issuances of commercial paper of $18.7 million. During 2016, net cash used in financing activities includes the payment of dividends of $95.8 million and the payment of financing costs of $8.4 million, partially offset by net issuances of commercial paper of $70.9 million and net proceeds from the issuance of debt of $24.5 million.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's discussion and analysis of financial condition and results of operations is based on our consolidated 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 Consolidated 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.

We have identified the policies and related procedures below as critical to understanding our historical and future performance, as these polices affect the reported amounts of revenue and are the more significant areas involving management's judgments and estimates.

Regulatory Assets and Liabilities

Our operations are subject to the provisions of ASC 980, *Regulated Operations* (ASC 980). Our regulatory assets are the probable future revenues associated with certain costs to be recovered from customers through the ratemaking process, including our estimate of amounts recoverable for natural gas and electric supply purchases. Regulatory liabilities are the probable future reductions in revenues associated with amounts to be credited to customers through the ratemaking process. We determine which costs are recoverable by consulting previous rulings by state regulatory authorities in jurisdictions where we operate or other factors that lead us to believe that cost recovery is probable. This accounting treatment is impacted by the uncertainties of our regulatory environment, anticipated future regulatory decisions and their impact. If any part of our operations becomes no longer subject to the provisions of ASC 980, or facts and circumstances lead us to conclude that a recorded regulatory asset is no longer probable of recovery, we would record a charge to earnings, which could be material. In addition, we would need to determine if there was any impairment to the carrying costs of the associated plant and inventory assets.

While we believe that our assumptions regarding future regulatory actions are reasonable, different assumptions could materially affect our results. See Note 5 – Regulatory Assets and Liabilities, to the Consolidated Financial Statements for further discussion.

Pension and Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefits for eligible employees. Our reported costs of providing pension and other postretirement benefits, as described in Note 15 - Employee Benefit Plans, to the Consolidated Financial Statements, are dependent upon numerous factors including the provisions of the plans, changing employee demographics, rate of return on plan assets and other economic conditions, and various actuarial calculations, assumptions, and accounting mechanisms. As a result of these factors, significant portions of pension and other postretirement benefit costs recorded in any period do not reflect (and are generally greater than) the actual benefits provided to plan participants. Due to the complexity of these calculations, the long-term nature of the obligations, and the importance of the assumptions utilized, the determination of these costs is considered a critical accounting estimate.

Assumptions

Key actuarial assumptions utilized in determining these costs include:

- Discount rates used in determining the future benefit obligations;
- Expected long-term rate of return on plan assets; and
- Mortality assumptions.

We review these assumptions on an annual basis and adjust them as necessary. The assumptions are based upon market interest rates, past experience and management's best estimate of future economic conditions.

We set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. Based on this analysis as of December 31, 2018, our discount rate on the NorthWestern Corporation pension plan is 4.15% and on the NorthWestern Energy pension plan is 4.20%.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Our expected long-term rate of return on assets assumption are 4.23% and 5.06% on the NorthWestern Corporation and NorthWestern Energy pension plan, respectively, for 2019.

Cost Sensitivity

The following table reflects the sensitivity of pension costs to changes in certain actuarial assumptions (in thousands):

Actuarial Assumption	Change in Assumption	Impact on Pension Cost	Impact on Projected Benefit Obligation
Discount rate	0.25 %	$ (1,816)	$ (19,437)
	(0.25)%	1,905	20,465
Rate of return on plan assets	0.25 %	(1,435)	N/A
	(0.25)%	1,435	N/A

Accounting Treatment

We recognize the funded status of each plan as an asset or liability in the Consolidated Balance Sheets. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets, which reduces the volatility of reported pension costs. If necessary, the excess is amortized over the average remaining service period of active employees.

Due to the various regulatory treatments of the plans, our financial statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. Regulatory assets have been recognized for the obligations that will be included in future cost of service.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized. Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We currently estimate that as of December 31, 2018, we have approximately $258 million of consolidated NOLs prior to consideration of unrecognized tax benefits to offset federal taxable income in future years. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ significantly from these estimates.

The interpretation of tax laws involves uncertainty. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows and adjustments to tax-related assets and liabilities could be material. The uncertainty and judgment involved in the determination and filing of income taxes is accounted for by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. 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 $56.2 million as of December 31, 2018. The resolution of tax matters in a particular future period could have a material impact on our provision for income taxes, results of operations and our cash flows.

Qualifying Facilities Liability

Our electric QF liability consists of unrecoverable costs associated with contracts covered under PURPA that are part of a 2002 stipulation with the MPSC and other parties. Under the terms of these contracts, we are required to purchase minimum amounts of energy at prices ranging from $63 to $136 per MWH through 2029. Our estimated gross contractual obligation is approximately $709.8 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $567.2 million through 2029. We maintain an electric QF liability based on the net present value (discounted at 7.75%) of the difference between our estimated obligations under the QFs and the fixed amounts recoverable in rates.

The liability was established based on certain assumptions and projections over the contract terms related to pricing, estimated output and recoverable amounts. Since the liability is based on projections over the next several years, actual output, changes in pricing, contract amendments and regulatory decisions relating to these facilities could significantly impact the liability and our results of operations in any given year. In assessing the liability each reporting period, we compare our assumptions to actual results and make adjustments as necessary for that period.

One of the contracts contains variable pricing terms, which exposes us to price escalation risks. The estimated annual escalation rate for this contract is a key assumption and is based on a combination of historical actual results and market data available for future projections. In recording the electric QF liability, we estimated an annual escalation rate of 3% over the remaining term of the contract (through June 2024). The actual escalation rate changes annually, which could significantly impact the liability and our results of operations.

NEW ACCOUNTING STANDARDS

See Note 2 - Significant Accounting Policies, to the Consolidated Financial Statements, included in Item 8 herein for a discussion of new accounting standards.

ITEM 7A. 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 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. The $400 million revolving credit facility bears interest at the lower of prime plus a credit spread, ranging from 0.00% to 0.75%, or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. In addition, on March 27, 2018, we entered into a $25 million revolving credit facility, maturing March 27, 2020, 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 December 31, 2018, we had approximately $290 million in borrowings under our revolving credit facilities. A 1% increase in interest rates would increase our annual interest expense by approximately $3.1 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 mechanism, a deadband and a sharing mechanism.

Counterparty Credit Risk

We are exposed to counterparty credit risk related to the ability of 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 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial information, including the reports of independent registered public accounting firm, the quarterly financial information, and the financial statement schedule, required by this Item 8 is set forth on pages F-1 to F-48 of this Annual Report on Form 10-K and is hereby incorporated into this Item 8 by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 December 31, 2018, 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.

Management's Report on Internal Control over Financial Reporting

The management of NorthWestern is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board regarding the preparation and fair presentation of published financial statements.

All internal controls over financial reporting, no matter how well designed, have inherent limitations, including the possibility of human error and the circumvention or overriding of controls. Therefore, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Our management, including our chief executive officer and chief financial officer, assessed the effectiveness of our internal control over financial reporting as of December 31, 2018. In making its assessment of internal control over financial reporting, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on our evaluation, management concluded that, as of December 31, 2018, our internal control over financial reporting was effective based on those criteria.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. Their report appears on page F-3.

ITEM 9B. OTHER INFORMATION

Not applicable.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors and corporate governance will be set forth in NorthWestern Corporation's Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to our Executive Officers is included in Item 1 to this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this Item will be set forth in NorthWestern Corporation's Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

Information required by this item will be set forth in NorthWestern Corporation's Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information concerning relationships and related transactions of the directors and officers of NorthWestern Corporation and director independence will be set forth in NorthWestern Corporation's Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information concerning fees paid to the principal accountant for each of the last two years will be set forth in NorthWestern Corporation's Proxy Statement for its 2019 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULE

The following documents are filed as part of this report:

(1) Consolidated Financial Statements.

The following items are included in Part II, Item 8 of this annual report on Form 10-K:

CONSOLIDATED FINANCIAL STATEMENTS:

(2) Financial Statement Schedule

Schedule II, Valuation and Qualifying Accounts, is included in Part II, Item 8 of this annual report on Form 10-K. All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or the Notes thereto.

(3) Exhibits.

The exhibits listed below are hereby filed with the SEC, as part of this Annual Report on Form 10-K. Certain of the following exhibits have been previously filed with the SEC pursuant to the requirements of the Securities Act of 1933 or the Securities Exchange Act of 1934. Such exhibits are identified by the parenthetical references following the listing of each such exhibit and are incorporated by reference. We will furnish a copy of any exhibit upon request, but a reasonable fee may be charged to cover our expenses in furnishing such exhibit.

Exhibit Number	Description of Document
1.1	Equity Distribution Agreement, dated as of September 6, 2017, between NorthWestern Corporation and Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC (incorporated by reference to Exhibit 1.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated September 6, 2017, Commission File No. 1-10499).
2.1(a)	Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
2.1(b)	Order Confirming the Second Amended and Restated Plan of Reorganization of NorthWestern Corporation (incorporated by reference to Exhibit 2.2 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
3.1(a)	Amended and Restated Certificate of Incorporation of NorthWestern Corporation, dated November 1, 2004 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 20, 2004, Commission File No. 1-10499).
3.1(b)	Amended and Restated Certificate of Incorporation of NorthWestern Corporation, dated May 3, 2016 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated May 18, 2016, Commission File No. 1-10499).
3.2(a)	Amended and Restated By-Laws of NorthWestern Corporation, dated October 31, 2011 (incorporated by reference to Exhibit 3.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 31, 2011, Commission File No. 1-10499).
3.2(b)	Amended and Restated Bylaws of NorthWestern Corporation, dated May 12, 2016 (incorporated by reference to Exhibit 3.2 of NorthWestern Corporation's Current Report on Form 8-K, dated May 18, 2016, Commission File No. 1-10499).
4.1(a)	General Mortgage Indenture and Deed of Trust, dated as of August 1, 1993, from NorthWestern Corporation to The Chase Manhattan Bank (National Association), as Trustee (incorporated by reference to Exhibit 4(a) of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 1993, Commission File No. 1-10499).
4.1(b)	Supplemental Indenture, dated as of November 1, 2004, by and between NorthWestern Corporation (formerly known as Northwestern Public Service Company) and JPMorgan Chase Bank (successor by merger to The Chase Manhattan Bank (National Association)), as Trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.5 of NorthWestern Corporation's Current Report on Form 8-K, dated November 1, 2004, Commission File No. 1-10499).
4.1(c)	Eighth Supplemental Indenture, dated as of May 1, 2008, by and between NorthWestern Corporation and The Bank of New York, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 10-Q for the quarter ended June 30, 2008, Commission File No. 1-10499).
4.1(d)	Ninth Supplemental Indenture, dated as of May 1, 2010, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation’s Current Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.1(e)	Tenth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon, as trustees under the General Mortgage Indenture and Deed of Trust dated as of August 1, 1993 (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.1(f)	Eleventh Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).
4.1(g)	Twelfth Supplemental Indenture, dated as of December 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated December 19, 2014, Commission File No. 1-10499).
4.1(h)	Thirteenth Supplemental Indenture, dated as of September 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation’s Current Report on Form 8-K, dated September 29, 2015, Commission File No. 1-10499).

4.1(i)	Fourteenth Supplemental Indenture, dated as of June 1, 2016, between the NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 21, 2016, Commission File No. 1-10499).
4.1(j)	Fifteenth Supplemental Indenture, dated as of September 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 6, 2016, Commission File No. 1-10499).
4.1(k)	Eighteenth Supplemental Indenture to the Mortgage and Deed of Trust, dated as of August 5, 1994 (incorporated by reference to Exhibit 99(b) of The Montana Power Company's Registration Statement on Form S-3, dated December 5, 1994, Commission File No. 033-56739).
4.1(l)	Twenty-Eighth Supplemental Indenture, dated as of October 1, 2009, by and between NorthWestern Corporation and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, Commission File No. 1-10499).
4.1(m)	Twenty-Ninth Supplemental Indenture, dated as of May 1, 2010, among NorthWestern Corporation and The Bank of New York Mellon and Ming Ryan, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
4.1(n)	Thirtieth Supplemental Indenture, dated as of August 1, 2012, between NorthWestern Corporation and The Bank of New York Mellon and Philip L. Watson, as trustees under the Mortgage and Deed of Trust dated as of October 1, 1945 (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 10, 2012, Commission File No. 1-10499).
4.1(o)	Thirty-First Supplemental Indenture, dated as of December 1, 2013, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2013, Commission File No. 1-10499).
4.1(p)	Thirty-Second Supplemental Indenture, dated as of November 1, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4 (n) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).
4.1(q)	Thirty-Third Supplemental Indenture, dated as of November 14, 2014, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 14, 2014, Commission File No. 1-10499).
4.1(r)	Thirty-Fourth Supplemental Indenture, dated as of January 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Phillip L. Watson, as trustees (incorporated by reference to Exhibit 4.4 (p) of the Company's Report on Form 10-K for the year ended December 31, 2014, Commission File No. 1-10499).
4.1(s)	Thirty-Fifth Supplemental Indenture, dated as of June 1, 2015, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated June 29, 2015, Commission File No. 1-10499).
4.1(t)	Thirty-Sixth Supplemental Indenture, dated as of August 1, 2016, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.4 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.1(u)	Thirty-Seventh Supplemental Indenture, dated as of November 1, 2017, among NorthWestern Corporation and The Bank of New York Mellon and Beata Harvin, as trustees (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated November 8, 2017, Commission File No. 1-10499).
4.2(a)	Indenture, dated as of August 1, 2016, between City of Forsyth, Rosebud County, Montana and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.1 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.2(b)	Loan Agreement, dated as of August 1, 2016, between NorthWestern Corporation and the City of Forsyth, Montana, related to the issuance of City of Forsyth Pollution Control Revenue Bonds Series 2016 (incorporated by reference to Exhibit 4.2 of the Company's Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.2(c)	Bond Delivery Agreement, dated as of August 1, 2016, between NorthWestern Corporation and U.S. Bank National Association, as trustee agent (incorporated by reference to Exhibit 4.3 of NorthWestern Corporation's Current Report on Form 8-K, dated August 16, 2016, Commission File No. 1-10499).
4.3	First Mortgage and Deed of Trust, dated as of October 1, 1945, by The Montana Power Company in favor of Guaranty Trust Company of New York and Arthur E. Burke, as trustees (incorporated by reference to Exhibit 7(e) of The Montana Power Company's Registration Statement, Commission File No. 002-05927).

10.1(a) †	NorthWestern Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, as amended April 21, 2010 (incorporated by reference to Exhibit 10.3 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(b) †	NorthWestern Corporation 2009 Officers Deferred Compensation Plan, as amended April 21, 2010 (incorporated by reference to Exhibit 10.4 of NorthWestern Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, Commission File No. 1-10499).
10.1(c) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated December 5, 2011, Commission File No. 1-10499).
10.1(d) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated December 12, 2012, Commission File No. 1-10499).
10.1(e) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated December 10, 2013, Commission File No. 1-10499).
10.1(f) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 18, 2014, Commission File No. 1-10499).
10.1(g) †	NorthWestern Corporation Amended and Restated Equity Compensation Plan, as amended effective July 1, 2014 (incorporated by reference to Appendix A to NorthWestern Corporation's Proxy Statement for the 2014 Annual Meeting of Shareholders filed on March 7, 2014, Commission File No. 1-10499).
10.1(h) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated December 22, 2014, Commission File No. 1-10499).
10.1(i) †	NorthWestern Corporation Key Employee Severance Plan 2016 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated October 25, 2016, Commission File No. 1-10499).
10.1(j) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated December 13, 2016, Commission File No. 1-10499).
10.1(k) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 23, 2017, Commission File No. 1-10499).
10.1(l) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 16, 2018, Commission File No. 1-10499).
10.1(m) †	NorthWestern Energy 2019 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2018, Commission File No. 1-10499).
10.1(n) †	Form of NorthWestern Corporation Executive Retirement/Retention Program Restricted Share Unit Award Agreement (incorporated by reference to Exhibit 99.02 of NorthWestern Corporation's Current Report on Form 8-K, dated December 19, 2018, Commission File No. 1-10499).
10.2(a)	Commercial Paper Dealer Agreement between NorthWestern Corporation and Merrill Lynch, Pierce, Fenner & Smith Incorporated, dated as of February 3, 2011 (incorporated by reference to Exhibit 10.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 8, 2011, Commission File No. 1-10499).
10.2(b)	Third Amended and Restated Credit Agreement, dated December 12, 2016, among NorthWestern Corporation, as borrower, the several banks and other financial institutions or entities from time to time parties to the agreement, as lenders, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Credit Suisse Securities (USA) LLC as joint lead arrangers; Credit Suisse Securities (USA) LLC as syndication agent; Keybank National Association, MUFG Union Bank, N.A. and U.S. Bank National Association, as co-documentation agents; 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 December 12, 2016, Commission File No. 1-10499).
10.2(c)	Bond Purchase Agreement, dated as of October 31, 2017, between NorthWestern Corporation and initial purchasers (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation’s Current Report on form 10-Q, dated November 2, 2017, Commission File No. 1-10499).
21*	Subsidiaries of NorthWestern Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm
24*	Power of Attorney (included on the signature page of this Annual Report on Form 10-K)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002

32.1*	Certification of Robert C. Rowe pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Brian B. Bird pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

† Management contract or compensatory plan or arrangement.
* Filed herewith.

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instructions or are not applicable, and, therefore, have been omitted.

ITEM 16. FORM 10-K SUMMARY

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWESTERN CORPORATION

February 12, 2019	By:	/s/ ROBERT C. ROWE
		Robert C. Rowe
		President and Chief Executive Officer

POWER OF ATTORNEY

We, the undersigned directors and/or officers of NorthWestern Corporation, hereby severally constitute and appoint Robert C. Rowe and Crystal D. Lail, and each of them with full power to act alone, our true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution and revocation, for each of us and in our name, place, and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, and hereby grant unto such attorneys-in-fact and agents, and each of them, the full power and authority to do each and every act and thing requisite and necessary to be done in and about the foregoing, as fully to all intents and purposes as each of us might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their respective substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ STEPHEN P. ADIK Stephen P. Adik	Chairman of the Board	February 12, 2019
/s/ ROBERT C. ROWE Robert C. Rowe	President, Chief Executive Officer and Director (Principal Executive Officer)	February 12, 2019
/s/ BRIAN B. BIRD Brian B. Bird	Chief Financial Officer (Principal Financial Officer)	February 12, 2019
/s/ CRYSTAL D. LAIL Crystal D. Lail	Vice President and Controller (Principal Accounting Officer)	February 12, 2019
/s/ ANTHONY T. CLARK Anthony T. Clark	Director	February 12, 2019
/s/ DANA J. DYKHOUSE Dana J. Dykhouse	Director	February 12, 2019
/s/ JAN R. HORSFALL Jan R. Horsfall	Director	February 12, 2019
/s/ BRITT E. IDE Britt E. Ide	Director	February 12, 2019
/s/ JULIA L. JOHNSON Julia L. Johnson	Director	February 12, 2019
/s/ LINDA G. SULLIVAN Linda G. Sullivan	Director	February 12, 2019

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULE

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
NorthWestern Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NorthWestern Corporation and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2018, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 11, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 11, 2019
We have served as the Company's auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
NorthWestern Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Northwestern Corporation and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the financial statements as of and for the year ended December 31, 2018, of the Company and our report dated February 11, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 11, 2019

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2018	**2017**	**2016**
Revenues			
Electric	$ 921,093	$ 1,037,053	$ 1,011,595
Gas	270,916	268,599	245,652
Total Revenues	1,192,009	1,305,652	1,257,247
Operating Expenses			
Cost of sales	272,883	410,349	400,973
Operating, general and administrative	307,119	294,803	293,863
Property and other taxes	171,259	162,614	148,098
Depreciation and depletion	174,476	166,137	159,336
Total Operating Expenses	925,737	1,033,903	1,002,270
Operating Income	266,272	271,749	254,977
Interest Expense, net	(91,988)	(92,263)	(94,970)
Other Income (Expense), net	3,966	(3,415)	(3,482)
Income Before Income Taxes	178,250	176,071	156,525
Income Tax Benefit (Expense)	18,710	(13,368)	7,647
Net Income	$ 196,960	$ 162,703	$ 164,172
Average Common Shares Outstanding	49,985	48,558	48,299
Basic Earnings per Average Common Share	$ 3.94	$ 3.35	$ 3.40
Diluted Earnings per Average Common Share	$ 3.92	$ 3.34	$ 3.39

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2018	**2017**	**2016**
Net Income	$ 196,960	$ 162,703	$ 164,172
Other comprehensive income (loss), net of tax:			
Reclassification of net losses (gains) on derivative instruments	498	371	(1,338)
Postretirement medical liability adjustment	213	773	195
Foreign currency translation	270	(202)	25
Total Other Comprehensive Income (Loss)	981	942	(1,118)
Comprehensive Income	$ 197,941	$ 163,645	$ 163,054

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31, 2018	2017
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,860	$ 8,473
Restricted cash	7,451	3,556
Accounts receivable, net	162,373	182,282
Inventories	50,815	52,432
Regulatory assets	38,431	37,669
Other	10,755	11,947
Total current assets	**277,685**	**296,359**
Property, plant, and equipment, net	4,521,318	4,358,265
Goodwill	357,586	357,586
Regulatory assets	437,581	354,316
Other noncurrent assets	50,206	54,391
Total Assets	**$ 5,644,376**	**$ 5,420,917**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of capital leases	$ 2,298	$ 2,133
Short-term borrowings	—	319,556
Accounts payable	87,043	85,160
Accrued expenses	216,792	210,047
Regulatory liabilities	40,876	15,342
Total current liabilities	**347,009**	**632,238**
Long-term capital leases	19,915	22,213
Long-term debt	2,102,345	1,793,416
Deferred income taxes	394,618	340,729
Noncurrent regulatory liabilities	438,285	417,701
Other noncurrent liabilities	399,822	415,705
Total Liabilities	**3,701,994**	**3,622,002**
Commitments and Contingencies (Note 19)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 53,889,410 and 50,323,649, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	539	530
Treasury stock at cost	(95,546)	(96,376)
Paid-in capital	1,499,070	1,445,181
Retained earnings	548,253	458,352
Accumulated other comprehensive loss	(9,934)	(8,772)
Total Shareholders' Equity	**1,942,382**	**1,798,915**
Total Liabilities and Shareholders' Equity	**$ 5,644,376**	**$ 5,420,917**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2018	2017	2016
OPERATING ACTIVITIES:			
Net Income	$ 196,960	$ 162,703	164,172
Items not affecting cash:			
Depreciation and depletion	174,476	166,137	159,336
Amortization of debt issue costs, discount and deferred hedge gain	4,645	4,794	2,117
Stock-based compensation costs	7,683	5,563	6,731
Equity portion of allowance for funds used during construction	(4,165)	(5,701)	(4,589)
Loss (gain) on disposition of assets	87	(415)	(15)
Deferred income taxes	(13,189)	12,363	(8,184)
Changes in current assets and liabilities:			
Accounts receivable	19,909	(22,726)	(5,146)
Inventories	1,617	(3,226)	4,252
Other current assets	1,218	827	(2,384)
Accounts payable	(3,805)	3,615	3,639
Accrued expenses	7,862	4,844	25,124
Regulatory assets	(554)	12,372	1,871
Regulatory liabilities	25,534	(11,019)	(54,629)
Other noncurrent assets	(9,533)	(14,780)	(7,311)
Other noncurrent liabilities	(26,760)	7,387	1,820
Cash Provided by Operating Activities	381,985	322,738	286,804
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(283,966)	(276,438)	(287,901)
Acquisitions	(18,504)	—	—
Proceeds from sale of assets	71	379	1,354
Investment in equity securities	(2,500)	—	—
Cash Used in Investing Activities	(304,899)	(276,059)	(286,547)
FINANCING ACTIVITIES:			
Dividends on common stock	(109,202)	(101,270)	(95,765)
Proceeds from issuance of common stock, net	44,796	53,669	—
Issuance of long-term debt	—	250,000	249,660
Repayment of long-term debt	—	(250,000)	(225,205)
Line of credit borrowings, net	308,000	—	—
(Repayments) issuances of short-term borrowings, net	(319,556)	18,745	70,937
Treasury stock activity	2,249	1,083	(561)
Financing costs	(91)	(16,382)	(8,432)
Cash Used In Financing Activities	(73,804)	(44,155)	(9,366)
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	3,282	2,524	(9,109)
Cash, Cash Equivalents, and Restricted Cash, beginning of period	12,029	9,505	18,614
Cash, Cash Equivalents, and Restricted Cash, end of period	**$ 15,311**	**$ 12,029**	**$ 9,505**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(in thousands, except per share data)

	Number of Common Shares	Number of Treasury Shares	Common Stock	Paid in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance at December 31, 2015	**51,789**	**3,617**	**$ 518**	**$1,376,291**	**$ (93,948)**	**$ 325,909**	**$ (8,596)**	**$ 1,600,174**
Net income	—	—	—	—	—	164,172	—	164,172
Accounting standard adoption (1)	—	—	—	—	—	2,603	—	2,603
Foreign currency translation adjustment	—	—	—	—	—	—	25	25
Reclassification of net gains on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	(1,338)	(1,338)
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	195	195
Stock based compensation	169	9	—	6,690	(2,874)	—	—	3,816
Issuance of shares	—	—	2	1,290	1,053	—	—	2,345
Dividends on common stock ($2.00 per share)	—	—	—	—	—	(95,765)	—	(95,765)
Balance at December 31, 2016	**51,958**	**3,626**	**$ 520**	**$1,384,271**	**$ (95,769)**	**$ 396,919**	**$ (9,714)**	**$ 1,676,227**
Net income	—	—	—	—	—	162,703	—	162,703
Foreign currency translation adjustment	—	—	—	—	—	—	(202)	(202)
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	371	371
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	773	773
Stock based compensation	134	—	—	5,520	(1,979)	—	—	3,541
Issuance of shares	889	(17)	10	55,390	1,372	—	—	56,772
Dividends on common stock ($2.10 per share)	—	—	—	—	—	(101,270)	—	(101,270)
Balance at December 31, 2017	**52,981**	**3,609**	**$ 530**	**$1,445,181**	**$ (96,376)**	**$ 458,352**	**$ (8,772)**	**$ 1,798,915**
Net income	—	—	—	—	—	196,960	—	196,960
Foreign currency translation adjustment	—	—	—	—	—	—	270	270
Reclassification of net losses on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	498	498
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	213	213
Reclassification of certain tax effects from AOCL	—	—	—	—	—	2,143	(2,143)	—
Stock based compensation	72	12	—	7,642	(668)	—	—	6,974
Issuance of shares	836	(55)	9	46,247	1,498	—	—	47,754
Dividends on common stock ($2.20 per share)	—	—	—	—	—	(109,202)	—	(109,202)
Balance at December 31, 2018	**53,889**	**3,566**	**$ 539**	**$1,499,070**	**$ (95,546)**	**$ 548,253**	**$ (9,934)**	**$ 1,942,382**

(1) We elected to early adopt the provisions of Financial Accounting Standards Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting, in the fourth quarter of 2016 as of January 1, 2016, resulting in a cumulative-effect adjustment to Retained Earnings for excess tax benefits.

See Notes to Consolidated Financial Statements

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 726,400 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Consolidated Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the SEC. The preparation of financial statements in conformity with 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 accompanying Consolidated Financial Statements include our accounts together with those of our wholly and majority-owned or controlled subsidiaries. All intercompany balances and transactions have been eliminated from the Consolidated Financial Statements. Events occurring subsequent to December 31, 2018, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

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 QF plants. We identified one QF contract that may constitute a VIE. We entered into a power purchase contract in 1984 with this 35 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 MWH (energy payment). 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, our estimated gross contractual payments aggregate to approximately $171.0 million through 2024. For further discussion of our gross QF liability, see Note 19 - Commitments and Contingencies. During the years ended December 31, 2018, 2017 and 2016 purchases from this QF were approximately $25.6 million, $16.3 million, and $25.5 million, respectively.

(2) Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, asset retirement obligations, regulatory assets and liabilities, uncollectible accounts, our QF liability, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers, but not yet billed at month-end.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Restricted Cash

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.3 million and $2.9 million at December 31, 2018 and December 31, 2017, respectively. Receivables include unbilled revenues of $78.2 million and $89.1 million at December 31, 2018 and December 31, 2017, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2018	2017
Materials and supplies	$ 36,926	$ 34,630
Storage gas and fuel	13,889	17,802
Total Inventories	$ 50,815	$ 52,432

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, Regulated Operations. Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Consolidated Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Consolidated Statements of Income at that time. This would result in a charge to earnings and accumulated other comprehensive loss (AOCL), net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, Derivatives and Hedging. All derivatives are recognized in the Consolidated Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated other comprehensive loss (AOCL) and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that are designated as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 9 - Risk Management and Hedging Activities, for further discussion of our derivative activity.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, AFUDC, and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under capital lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. This rate averaged 7.1%, 7.2%, and 7.2%, for Montana for 2018, 2017, and 2016, respectively. This rate averaged 6.7%, 7.2%, and 7.2%, for South Dakota for 2018, 2017, and 2016, respectively. AFUDC capitalized totaled $5.9 million, $8.5 million, and $7.0 million for the years ended December 31, 2018, 2017, and 2016, respectively, for Montana and South Dakota combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from three to 50 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.0%, 3.0%, and 3.0% for 2018, 2017, and 2016, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in noncurrent regulatory liabilities.

Pension and Postretirement Benefits

We have liabilities under defined benefit retirement plans and a postretirement plan that offers certain health care and life insurance benefits to eligible employees and their dependents. The costs of these plans are dependent upon numerous factors, assumptions and estimates, including determination of discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Other Noncurrent Liabilities

Other noncurrent liabilities consisted of the following (in thousands):

	December 31,	
	2018	2017
Pension and other employee benefits	$ 125,809	$ 111,202
Future QF obligation, net	102,260	132,786
Customer advances	50,089	45,376
Asset retirement obligations	40,659	39,286
Environmental	28,741	29,326
Other	52,264	57,729
Total Noncurrent Liabilities	$ 399,822	$ 415,705

Income Taxes

We follow the liability method in accounting for income taxes. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Consolidated Income Statements and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost.

Accounting Standards Issued

Leases - In February 2016, the FASB issued revised guidance on accounting for leases. The new standard requires a lessee to recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term for all leases with terms longer than 12 months. Leases with a term of 12 months or less will be accounted for similar to existing guidance for operating leases. Recognition, measurement and presentation of expenses will depend on classification as a finance or operating lease.

We adopted this standard for interim and annual periods beginning January 1, 2019, as required, and used the modified retrospective method of adoption. We elected a package of practical expedients that allow us to carry forward historical conclusions related to (1) whether any expired or existing contract is a lease or contains a lease, (2) the lease classification of any expired or existing leases and easements, and (3) the initial direct costs for any existing leases. In addition, as our easements are primarily entered into in perpetuity they do not meet the definition of a lease in accordance with this guidance. We did not restate comparative periods upon adoption. We have one capital lease that will be reclassified to a finance lease. We also lease office equipment and facilities under various long-term operating leases. These operating leases will increase our assets and liabilities by approximately $3 million. As a result, this guidance will have minimal impact on our Consolidated Financial Statements and disclosures.

Accounting Standards Adopted

Revenue Recognition - In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance on the recognition of revenue from contracts with customers, which will supersede nearly all existing revenue recognition guidance under GAAP. Under the new standard, entities will recognize revenue to depict the transfer of goods and services to customers in amounts that reflect the payment to which the entity expects to be entitled in exchange for those goods or services. The guidance also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers.

We adopted this standard for interim and annual periods beginning January 1, 2018, as required, and used the modified retrospective method of adoption, with no material impact on our Consolidated Financial Statements or internal controls. We have also elected to utilize certain practical expedients, which allow us to apply the standard to open contracts at the date of adoption and to reflect the aggregate effect of all modifications when identifying performance obligations and allocating the transaction price for contracts modified before the effective date. We completed a comprehensive review of contracts and their associated terms and conditions. Based on this analysis, we did not have a cumulative effect adjustment to retained earnings at January 1, 2018. See Note 20, Revenue from Contracts with Customers, for additional disclosures including revenue recognition policies and our disaggregated revenues by segment for each geographical region.

Retirement Benefits - On January 1, 2018, we adopted Accounting Standards Update (ASU) 2017-07, Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, as issued by the FASB. Under ASU 2017-07, companies are required to disaggregate the current service cost component from the other components of net periodic benefit cost and present it with other current compensation costs for related employees in the income statement and present the other components elsewhere in the income statement and outside of income from operations. In addition, only the service cost component of net periodic benefit cost is eligible for capitalization.

ASU 2017-07 was applied on a modified retrospective basis for the presentation of the other components of net periodic benefit cost in the Consolidated Statements of Income. Using the allowed practical expedient, we applied the amounts disclosed in the "Employee Benefit Plans" note to the 2017 Consolidated Financial Statements for the restatement of comparative information. The impact of the adoption of this guidance resulted in the reclassification of the other components of net benefit cost from operating, general, and administrative expense to other income (expense), net in the Consolidated Statements of Income. The following table summarizes the adjustments made to conform prior period classifications to the new guidance (in thousands):

	As Reported	Effect of Accounting Change	As Adjusted
	Year Ended December 31, 2017		
Operating, general and administrative	$ 305,137	$ (10,334)	$ 294,803
Other Income (Expense), net	6,919	(10,334)	(3,415)
	Year Ended December 31, 2016		
Operating, general and administrative	$ 302,893	$ (9,030)	$ 293,863
Other Income (Expense), net	5,548	(9,030)	(3,482)

ASU 2017-07 was applied prospectively for the capitalization of related costs in assets and did not have a material impact. As a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the current ratemaking treatment.

Statement of Cash Flows - In August 2016, the FASB issued guidance that addresses eight classification issues related to the presentation of cash receipts and cash payments in the statement of cash flows. We adopted this standard as of January 1, 2018, with no material impact to our Consolidated Statements of Cash Flows, and although the guidance requires retrospective treatment, we did not have any cash receipts or payments during the prior two years that needed to be reclassified.

In November 2016, the FASB issued guidance that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. We adopted this standard as of January 1, 2018 with retrospective application. For the twelve months ended December 31, 2017, this change resulted in a $4.4 million and $3.6 million increase in cash, cash equivalents and restricted cash at the beginning and end of the period on our Consolidated Statements of Cash Flows, respectively. In addition, removing the change in restricted cash from operating activities in the Consolidated Statements of Cash Flows resulted in a decrease of $0.9 million and $2.2 million in our cash provided by operating activities for the twelve months ended December 31, 2017 and 2016, respectively.

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

	December 31,		
	2018	**2017**	**2016**
Cash and cash equivalents	$ 7,860	$ 8,473	$ 5,079
Restricted cash	7,451	3,556	4,426
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 15,311	$ 12,029	$ 9,505

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Stranded Tax Effects in AOCL - In February 2018, the FASB issued guidance to allow a one-time reclassification from AOCL to retained earnings for stranded tax effects resulting from the new tax reform legislation. The amount of the reclassification is calculated on the basis of the difference between the historical and newly enacted tax rates for deferred tax liabilities and assets related to items within AOCL.

This amendment is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. Early adoption is permitted, including adoption in any interim reporting period for which financial statements have not yet been issued. We early adopted this guidance during the first quarter of 2018, through a one-time reclassification of $2.1 million of stranded tax effects from AOCL to retained earnings. Adoption of this guidance did not have a material impact on our consolidated financial position, results of operations or cash flows.

Disclosure Requirements for Defined Benefit Plans - In August 2018, the FASB issued amended guidance to add, remove, and clarify the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. During the fourth quarter of 2018, we early adopted this guidance with minimal impact to our disclosures in Note 15 - Employee Benefit Plans.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Cash paid (received) for:			
Income taxes	$ 55	$ 60	$ (2,922)
Interest	76,499	82,692	84,953
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	21,625	15,848	13,783

(3) Acquisition

Montana Wind Generation

In June 2018, we completed the purchase of the 9.7 MW Two Dot wind project near Two Dot, Montana for approximately $18.5 million. The Two Dot purchase price was allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition as follows (in thousands):

Purchase Price Allocation	
Assets Acquired	
Property Plant and Equipment, net	$ 18,542
Current Assets	26
Total Assets Acquired	18,568
Liabilities Assumed	
Accrued Expenses	64
Total Liabilities Assumed	64
Total Purchase Price	$ 18,504

(4) Regulatory Matters

Montana General Electric Rate Case

In September 2018, we filed an electric rate case with the MPSC requesting an annual increase to electric rates of approximately $34.9 million, which represents an approximate 6.6% increase in annual base revenues. Our request is based on a return on equity of 10.65% and an overall rate of return of 7.42% (except for Colstrip Unit 4, which the MPSC previously set for the life of the facility at a 10% return on equity and an 8.25% rate of return), based on approximately $2.35 billion of electric rate base and a capital structure of 51% debt and 49% equity.

We also requested that approximately $13.8 million of the proposed rate increase be approved on an interim basis effective November 1, 2018. We expect to receive a decision on our interim request after intervenor testimony is filed. If the MPSC does not issue a final order within nine months of the filing, the new requested rates may be placed into effect on an interim and refundable basis.

Key dates in the procedural schedule are expected to be as follows:

- Intervenor testimony - February 12, 2019
- NorthWestern rebuttal testimony and cross-intervenor testimony - April 5, 2019
- Hearing commences - May 13, 2019

Tax Cuts and Jobs Act

In December 2017, H.R.1 (the Tax Cuts and Jobs Act) was signed into law, which enacts significant changes to U.S. tax and related laws. The primary impact to us is a reduction of the federal corporate income tax rate from 35% to 21% effective January 1, 2018. Dockets were opened in each of our jurisdictions to investigate the customer benefit of this reduction in the federal corporate income tax rate. During 2018, we received approval of settlement agreements regarding the customer benefit of the Tax Cuts and Jobs Act, as described below.

- In Montana the settlement provides a one-time credit of approximately $20.5 million to customers in early 2019. This includes a $19.2 million credit to electric customers and $1.3 million credit to natural gas customers.
    - In addition to eligible customers receiving a one-time bill credit, the settlement also reduces rates for all natural gas customers by approximately $1.3 million annually beginning January 1, 2019, and provides funds for low-income energy assistance and weatherization programs.
    - The settlement also reflects the agreement of the intervening parties not to oppose our request to include up to $3.5 million of costs to address hazard tree removal in our current Montana rate case.
    - Issues related to the revaluation of deferred income taxes will be addressed in our current Montana rate case.

- In South Dakota we credited electric and natural gas customers approximately $3 million in the fourth quarter of 2018, and agreed to a two-year rate moratorium until January 1, 2021.

Cost Recovery Mechanisms

Electric Tracker - Effective July 1, 2017, the Montana legislature granted the MPSC discretion whether to approve an electric supply tracking mechanism. After considering our application in a contested case proceeding, the MPSC issued a final order in January 2019 approving a PCCAM with the following provisions:

- A baseline of power supply costs;
- Annual adjustment of customer prices to reflect a portion of the difference between the established base revenues and actual costs, to the extent such difference is outside a +/- $4.1 million "deadband" from the base, with 90% of the variance above or below the deadband is collected from or refunded to customers; and
- Retroactive implementation to the effective date of the new legislation (July 1, 2017).

Our 2018 results include a net reduction in the recovery of supply costs from customers of approximately $1.5 million for the period July 1, 2017 through December 31, 2018 in the Consolidated Statements of Income and a regulatory asset in the Consolidated Balance Sheet of approximately $6.9 million reflecting costs to be recovered from customers in excess of the deadband.

Montana Electric Tracker Open Dockets - 2015/2016 - 2016/2017 (2015-2017 Tracker Filings) - Under the previous statutory tracker mechanism, each year we submitted an electric tracker filing for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period, which were subject to a prudency review. The MPSC has approved interim rates for the 2015-2017 Tracker Filings, but has not established a schedule for adjudication of these filings.

(5) Regulatory Assets and Liabilities

We prepare our Consolidated Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

			December 31,	
			2018	2017
	Note Reference	Remaining Amortization Period	(in thousands)	
Income taxes	13	Plant Lives	$ 230,434	$ 163,605
Pension	15	Undetermined	130,193	115,504
Deferred financing costs		Various	34,080	37,090
Employee related benefits	15	Undetermined	19,458	17,729
Supply costs		1 Year	10,532	13,398
State & local taxes & fees		Various	15,532	10,896
Environmental clean-up	19	Various	11,221	12,399
Other		Various	24,562	21,364
Total Regulatory Assets			**$ 476,012**	**$ 391,985**
Removal cost	7	Various	$ 428,528	$ 408,451
Tax Cut and Jobs Act		1 Year	20,497	—
Supply costs		1 Year	15,453	10,357
Gas storage sales		21 Years	8,728	9,149
Deferred revenue		1 Year	—	2,201
State & local taxes & fees		1 Year	1,747	1,520
Environmental clean-up		Various	1,247	1,365
Other		Various	2,961	—
Total Regulatory Liabilities			**$ 479,161**	**$ 433,043**

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. See Note 13 - Income Taxes for further discussion.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The MPSC allows recovery of pension costs on a cash funding basis. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

Supply Costs

The MPSC, SDPUC and NPSC have authorized the use of electric and natural gas supply cost trackers that enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on natural gas supply costs under collected, or apply interest to an over collection, of 7.0% in Montana; 7.2% and 7.8% for electric and natural gas, respectively, in South Dakota; and 8.5% for natural gas in Nebraska.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase in rates, less the amount allocated to FERC jurisdictional customers and net of the related income tax benefit.

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 19 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. We record changes in the regulatory asset consistent with changes in our environmental liabilities. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Removal Cost

The anticipated costs of removing assets upon retirement are collected from customers in advance of removal activity as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, consistent with this regulated treatment, we reflect this accrual of removal costs for our regulated assets by increasing our regulatory liability. See Note 7 - Asset Retirement Obligations, for further information regarding this item.

Tax Cut and Jobs Act

The Tax Cuts and Jobs Act provided a customer benefit as a result of the lower statutory rate. This amount reflects credits due to customers in our Montana jurisdiction in the first quarter of 2019.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

(6) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	Estimated Useful Life	December 31, 2018	December 31, 2017
	(years)	(in thousands)	
Land, land rights and easements	50 – 96	$ 149,636	$ 148,507
Building and improvements	26 – 64	264,205	242,038
Transmission, distribution, and storage	15 – 85	3,341,001	3,163,463
Generation	25 – 50	1,193,117	1,187,346
Plant acquisition adjustment	25 – 50	686,328	685,417
Other	2 – 45	541,741	521,711
Construction work in process	—	110,076	69,902
Total property, plant and equipment		6,286,104	6,018,384
Less accumulated depreciation		(1,764,786)	(1,660,119)
Net property, plant and equipment		$ 4,521,318	$ 4,358,265

The plant acquisition adjustment balance above includes an amount related to our Beethoven wind project acquired in 2015, our hydro generating assets acquired in 2014, and the inclusion of our interest in Colstrip Unit 4 in rate base in 2009. The acquisition adjustment is being amortized on a straight-line basis over the estimated remaining useful life of each related asset in depreciation expense.

Plant and equipment under capital lease were $15.4 million and $17.5 million as of December 31, 2018 and 2017, respectively, which included $15.1 million and $17.1 million as of December 31, 2018 and 2017, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a capital lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2018				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 155,359	$ 60,758	$ 50,325	$ 309,163
Accumulated depreciation	42,235	31,542	37,955	88,985
December 31, 2017				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 153,682	$ 60,859	$ 49,968	$ 307,712
Accumulated depreciation	40,706	30,446	37,605	85,481

(7) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our property, plant and equipment and other noncurrent liabilities. The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the asset retirement obligation (ARO) is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, our obligation to plug and abandon oil and gas wells at the end of their life, and to remove all above-ground wind power facilities and restore the soil surface at the end of their life. The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2018	2017
Liability at January 1,	$ 39,286	$ 39,402
Accretion expense	2,031	2,062
Liabilities incurred	773	—
Liabilities settled	(63)	(61)
Revisions to cash flows	(1,368)	(2,117)
Liability at December 31,	$ 40,659	$ 39,286

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our hydroelectric generating facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Consolidated Financial Statements.

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. The recorded amounts of costs collected from customers through depreciation rates are classified as a regulatory liability in recognition of the fact that we have collected these amounts that will be used in the future to fund asset retirement costs and do not represent legal retirement obligations. See Note 5 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2018 and 2017.

(8) Goodwill

We completed our annual goodwill impairment test as of April 1, 2018 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.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2018	2017
Electric	$ 243,558	$ 243,558
Natural gas	114,028	114,028
Total Goodwill	$ 357,586	$ 357,586

(9) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a portion of our electric and natural gas supply requirements. 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.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines.

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale (NPNS); cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the NPNS scope exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no unrealized amounts recorded in the Consolidated Financial Statements at December 31, 2018 and 2017. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We limit credit risk in our commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties. We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements – standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements – standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements – standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

Interest Rate Swaps Designated as Cash Flow Hedges

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. We have no interest rate swaps outstanding. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCL. We reclassify these gains from AOCL into interest expense during the periods in which the hedged interest payments occur. The following table shows the effect of these interest rate swaps previously terminated on the Consolidated Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCL to Income	Amount Reclassified from AOCL into Income during the Year Ended December 31, 2018
Interest rate contracts	Interest Expense	$ 613

A pre-tax loss of approximately $15.9 million is remaining in AOCL as of December 31, 2018, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCL into interest expense during the next twelve months. These amounts relate to terminated swaps.

(10) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

Applicable accounting guidance establishes a hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Due to the short-term nature of cash and cash equivalents, accounts receivable, net, accounts payable, and short-term borrowings, the carrying amount of each such items approximate fair value. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. NPNS transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 9 - Risk Management and Hedging Activities for further discussion.

We record transfers between levels of the fair value hierarchy, if necessary, at the end of the reporting period. There were no transfers between levels for the periods presented.

December 31, 2018	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Margin Cash Collateral Offset	Total Net Fair Value
			(in thousands)		
Restricted cash equivalents	$ 6,669	$ —	$ —	$ —	$ 6,669
Rabbi trust investments	22,270	—	—	—	22,270
Total	**$ 28,939**	**$ —**	**$ —**	**$ —**	**$ 28,939**
December 31, 2017					
Restricted cash equivalents	2,648	$ —	$ —	$ —	$ 2,648
Rabbi trust investments	28,135	—	—	—	28,135
Total	**$ 30,783**	**$ —**	**$ —**	**$ —**	**$ 30,783**

Restricted cash equivalents represents amounts held in money market mutual funds. Rabbi trust investments represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,102,345	$ 2,117,912	$ 1,793,416	$ 1,901,915

Short-term borrowings as of December 31, 2017, consist of commercial paper and are not included in the table above as carrying value approximates fair value. The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(11) Unsecured Revolving Line of Credit

Unsecured Revolving Line of Credit

We have a $400 million revolving credit facility, which matures December 12, 2021. The facility includes an accordion feature that allows us to increase the size to $450 million with the consent of the lenders. The facility does not amortize and is unsecured. The facility bears interest at the lower of prime plus a credit spread, ranging from 0% to 0.75%, or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. A total of eight banks participate in the facility, with no one bank providing more than 16% of the total availability. In addition, on March 27, 2018, we entered into a $25 million revolving credit facility, maturing March 27, 2020, 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%. Commitment fees for the unsecured revolving lines of credit were $0.4 million and $0.5 million for the years ended December 31, 2018 and 2017. The weighted-average interest rate on commercial paper was 1.35% for the year ended December 31, 2017.

The availability under the facilities in place for the years ended December 31 is shown in the following table (in millions):

	2018	2017
Unsecured revolving line of credit, expiring December 2021	$ 400.0	$ 400.0
Unsecured revolving line of credit, expiring March 2020	25.0	—
	425.0	**400.0**
Amounts outstanding at December 31:		
LIBOR borrowings	308.0	—
Letters of credit	0.2	—
Commercial paper issuances	—	319.6
	308.2	**319.6**
Net availability as of December 31, 2018	**$ 116.8**	**$ 80.4**

Our covenants require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65%. In addition, there are 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 facilities would not trigger a default on any other obligations.

(12) Long-Term Debt and Capital Leases

Long-term debt and capital leases consisted of the following (in thousands):

	Due	December 31, 2018	December 31, 2017
Unsecured Debt:			
Unsecured Revolving Line of Credit	2021	$ 290,000	$ —
Unsecured Revolving Line of Credit	2020	18,000	—
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	26,977	26,977
Discount on Notes and Bonds and Debt Issuance Costs, Net	—	(12,292)	(13,221)
		$ 2,102,345	$ 1,793,416
Less current maturities		—	—
Total Long-Term Debt		$ 2,102,345	$ 1,793,416
Capital Leases:			
Total Capital Leases	Various	$ 22,213	$ 24,346
Less current maturities		(2,298)	(2,133)
Total Long-Term Capital Leases		$ 19,915	$ 22,213

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. All of such bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In November 2017, we issued $250 million aggregate principal amount of Montana First Mortgage Bonds, at a fixed interest rate of 4.03% maturing in 2047. The bonds are secured by our electric and natural gas assets in Montana. The bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended. Proceeds were used to redeem our 6.34%, $250 million of Montana First Mortgage Bonds due 2019.

As of December 31, 2018, we are in compliance with our financial debt covenants.

Other Long-Term Debt

The New Market Tax Credit (NMTC) financing is pursuant to Section 45D of the Internal Revenue Code of 1986 as amended, which was issued in association with a tax credit program related to the development and construction of a new office building in Butte, Montana. This financing agreement is structured with unrelated third party financial institutions (the Investor) and their wholly-owned community development entities (CDEs) in connection with our participation in qualified transactions under the NMTC program. Upon closing of this transaction in 2014, we entered into two loans totaling $27.0 million payable to the CDEs sponsoring the project, and provided an $18.2 million investment. In exchange for substantially all of the benefits derived from the tax credits, the Investor contributed approximately $8.8 million to the project. The NMTC is subject to recapture for a period of seven years. If the expected tax benefits are delivered without risk of recapture to the Investor and our performance obligation is relieved, we expect $7.9 million of the loan to be forgiven in July 2021. If we do not meet the conditions for loan forgiveness, we would be required to repay $27.0 million and would concurrently receive the return of our $18.2 million investment. As we are the primary beneficiary of the entities created in relation to the NMTC transaction, they have been consolidated as variable interest entities. The loans of $27.0 million are recorded in long-term debt and the investment of $18.2 million is recorded in other noncurrent assets in the Consolidated Balance Sheets.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and capital leases, during the next five years are $2.3 million in 2019, $20.5 million in 2020, $292.7 million in 2021, $2.9 million in 2022 and $3.1 million in 2023.

(13) Income Taxes

Income tax expense (benefit) is comprised of the following (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Federal			
Current	$ (5,526)	$ 806	$ 723
Deferred	(15,588)	17,378	(2,054)
Investment tax credits	(33)	166	(196)
State			
Current	38	33	10
Deferred	2,399	(5,015)	(6,130)
Income Tax (Benefit) Expense	$ (18,710)	$ 13,368	$ (7,647)

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 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 lower statutory tax rate will reduce the impact of these deductions. 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 reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31,		
	2018	2017	2016
Federal statutory rate	21.0 %	35.0%	35.0 %
State income tax, net of federal provisions	0.9	(1.9)	(2.4)
Impact of Tax Cuts and Jobs Act	(11.1)	—	—
Flow-through repairs deductions	(10.8)	(17.3)	(26.3)
Production tax credits	(6.1)	(6.3)	(7.0)
Plant and depreciation of flow through items	(1.2)	(1.3)	(2.9)
Share-based compensation	0.1	(0.2)	(1.1)
Prior year permanent return to accrual adjustments	(1.7)	(0.3)	(0.1)
Other, net	(1.6)	(0.1)	(0.1)
Effective tax rate	(10.5)%	7.6%	(4.9)%

The table below summarizes the significant differences in income tax (benefit) expense based on the differences between our effective tax rate and the federal statutory rate (in thousands).

	Year Ended December 31,		
	2018	2017	2016
Income Before Income Taxes	$ 178,250	$ 176,071	$ 156,525
Income tax calculated at federal statutory rate	37,433	61,625	54,784
Permanent or flow through adjustments:			
State tax income, net of federal provisions	1,613	(3,258)	(3,714)
Impact of Tax Cuts and Jobs Act	(19,840)	—	—
Flow-through repairs deductions	(19,323)	(30,490)	(41,111)
Production tax credits	(10,890)	(11,032)	(10,941)
Plant and depreciation of flow through items	(2,175)	(2,208)	(4,604)
Share-based compensation	228	(363)	(1,646)
Prior year permanent return to accrual adjustments	(2,978)	(629)	(128)
Other, net	(2,778)	(277)	(287)
	(56,143)	(48,257)	(62,431)
Income Tax (Benefit) Expense	$ (18,710)	$ 13,368	$ (7,647)

The income tax benefit during the twelve months ended December 31, 2018, includes finalization of the remeasurement of deferred taxes associated with the Tax Cuts and Jobs Act following the conclusion of the associated regulatory dockets. The income tax benefit during the twelve months ended December 31, 2016, was primarily due to the adoption of a tax accounting method change related to the costs to repair generation assets. This is reflected in the flow-through repairs deductions line due to the regulatory treatment.

The components of the net deferred income tax liability recognized in our Consolidated Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2018	2017
Production tax credit	$ 38,956	$ 28,067
Pension / postretirement benefits	30,634	26,887
NOL carryforward	28,326	68,840
Customer advances	13,190	11,949
Unbilled revenue	12,305	5,944
Compensation accruals	11,885	12,113
AMT credit carryforward	6,799	13,599
Environmental liability	5,810	5,821
Interest rate hedges	4,074	4,323
Reserves and accruals	1,100	1,126
QF obligations	557	234
Property taxes	523	432
Regulatory liabilities	77	114
Other, net	196	1,138
Deferred Tax Asset	**154,432**	**180,587**
Excess tax depreciation	(371,216)	(356,938)
Goodwill amortization	(119,454)	(117,971)
Flow through depreciation	(57,456)	(45,998)
Regulatory assets	(924)	(409)
Deferred Tax Liability	**(549,050)**	**(521,316)**
Deferred Tax Liability, net	**$ (394,618)**	**$ (340,729)**

At December 31, 2018 our total federal NOL carryforward is approximately $257.7 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $4.9 million in 2034; $174.6 million in 2036 and $78.2 million in 2037. Our state NOL carryforward as of December 31, 2018 is approximately $181.5 million. If unused, our state NOL carryforwards will expire as follows: $120.4 million in 2023 and $61.1 million in 2024. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

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. The change in unrecognized tax benefits is as follows (in thousands):

	2018	2017	2016
Unrecognized Tax Benefits at January 1	$ 57,473	$ 88,429	$ 92,387
Gross increases - tax positions in prior period	—	—	—
Gross decreases - tax positions in prior period	—	(22,973)	—
Gross increases - tax positions in current period	338	—	—
Gross decreases - tax positions in current period	(1,661)	(7,983)	(3,958)
Lapse of statute of limitations	—	—	—
Unrecognized Tax Benefits at December 31	$ 56,150	$ 57,473	$ 88,429

The reduction in unrecognized tax benefits during the twelve months ended December 31, 2017 reflects the effect of the lower statutory rate in the Tax Cuts and Jobs Act. Our unrecognized tax benefits include approximately $47.5 million and $47.8 million related to tax positions as of December 31, 2018 and 2017, respectively that, if recognized, would impact our annual effective tax rate. It is reasonably possible that our unrecognized tax benefits may decrease by up to approximately $20 million in the next 12 months due to expiration of statutes of limitation.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the years ended December 31, 2018 and 2017, we recognized $1.2 million and $0.8 million, respectively, of expense for interest and penalties in the Consolidated Statements of Income. As of December 31, 2018 and 2017, we had $2.7 million and $1.5 million, respectively, of interest accrued in the Consolidated Balance Sheets.

Our federal tax returns from 2000 forward remain subject to examination by the IRS.

(14) Comprehensive Income (Loss)

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

	December 31,								
	2018			2017			2016		
	Before-Tax Amount	Tax Expense	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit (Expense)	Net-of-Tax Amount	Before-Tax Amount	Tax Benefit (Expense)	Net-of-Tax Amount
Foreign currency translation adjustment	$ 270	$ —	$ 270	$ (202)	—	$ (202)	$ 25	$ —	$ 25
Reclassification of net losses (gains) on derivative instruments	614	(116)	498	613	(242)	371	(2,169)	831	(1,338)
Postretirement medical liability adjustment	346	(133)	213	1,257	(484)	773	317	(122)	195
Other comprehensive income (loss)	$ 1,230	$ (249)	$ 981	$ 1,668	$ (726)	$ 942	$ (1,827)	$ 709	$ (1,118)

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

	December 31,	
	2018	2017
Foreign currency translation	$ 1,448	$ 1,178
Derivative instruments designated as cash flow hedges	(11,633)	(9,981)
Postretirement medical plans	251	31
Accumulated other comprehensive loss	$ (9,934)	$ (8,772)

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

	Affected Line Item in the Consolidated Statements of Income	December 31, 2018 Year Ended Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)
Other comprehensive income before reclassifications		—	—	270	270
Amounts reclassified from AOCL	Interest Expense	498	—	—	498
Amounts reclassified from AOCL		—	213	—	213
Net current-period other comprehensive income (loss)		498	213	270	981
Reclassification of certain tax effects from AOCL		(2,150)	7	—	(2,143)
Ending Balance		$ (11,633)	$ 251	$ 1,448	$ (9,934)

	Affected Line Item in the Consolidated Statements of Income	December 31, 2017 Year Ended Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (10,352)	$ (742)	$ 1,380	$ (9,714)
Other comprehensive income before reclassifications		—	—	(202)	(202)
Amounts reclassified from AOCL	Interest Expense	371	—	—	371
Amounts reclassified from AOCL		—	773	—	773
Net current-period other comprehensive (loss) income		371	773	(202)	942
Ending Balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)

(15) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation plan, and the pension plan for our Montana employees is referred to as the NorthWestern Energy plan, and collectively they are referred to as the Plans. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plan's funded status is recognized as an asset or liability in our Consolidated Financial Statements. See Note 5 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value of plan assets, and a statement of the funded status (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2018	2017	2018	2017
Change in benefit obligation:				
Obligation at beginning of period	$ 696,796	$ 646,032	$ 22,921	$ 26,217
Service cost	11,776	10,994	398	456
Interest cost	24,420	25,633	578	715
Actuarial loss (gain)	(53,496)	41,719	(1,903)	(1,884)
Settlements	—	—	390	390
Benefits paid	(29,870)	(27,582)	(1,773)	(2,973)
Benefit Obligation at End of Period	$ 649,626	$ 696,796	$ 20,611	$ 22,921
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 586,508	$ 524,637	$ 20,380	$ 18,605
Return on plan assets	(40,528)	80,253	(866)	2,690
Employer contributions	9,200	9,200	929	2,058
Benefits paid	(29,870)	(27,582)	(1,773)	(2,973)
Fair value of plan assets at end of period	$ 525,310	$ 586,508	$ 18,670	$ 20,380
Funded Status	$ (124,316)	$ (110,288)	$ (1,941)	$ (2,541)
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	2,672	2,535	4,565	5,061
Total Assets	2,672	2,535	4,565	5,061
Current liability	—	—	(2,271)	(3,353)
Noncurrent liability	(126,988)	(112,823)	(4,235)	(4,249)
Total Liabilities	(126,988)	(112,823)	(6,506)	(7,602)
Net amount recognized	$ (124,316)	$ (110,288)	$ (1,941)	$ (2,541)
Amounts Recognized in Regulatory Assets Consist of:				
Prior service (cost) credit	—	(4)	7,922	9,955
Net actuarial loss	(116,425)	(105,545)	(1,910)	(1,735)
Amounts recognized in AOCL consist of:				
Prior service cost	—	—	(548)	(698)
Net actuarial gain	—	—	1,260	1,079
Total	$ (116,425)	$ (105,549)	$ 6,724	$ 8,601

The actuarial gain/loss is primarily due to the change in discount rate assumption and actual asset returns compared with expected amounts.

The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	NorthWestern Energy Pension Plan	
	December 31,	
	2018	2017
Projected benefit obligation	$ 592.5	$ 634.4
Accumulated benefit obligation	592.5	634.4
Fair value of plan assets	466.7	522.7

As of December 31, 2018, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2018	2017	2016	2018	2017	2016
Components of Net Periodic Benefit Cost						
Service cost	$ 11,776	$ 10,994	$ 11,759	$ 398	$ 456	$ 492
Interest cost	24,420	25,633	26,210	578	715	795
Expected return on plan assets	(28,207)	(23,964)	(28,248)	(954)	(846)	(1,042)
Amortization of prior service cost (credit)	4	4	246	(1,882)	(1,882)	(1,882)
Recognized actuarial loss	4,360	7,837	9,888	(79)	318	315
Settlement loss recognized	—	—	—	390	390	390
Net Periodic Benefit Cost (Credit)	$ 12,353	$ 20,504	$ 19,855	$ (1,549)	$ (849)	$ (932)

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2018 and 2017. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The increase in discount rate during 2018 decreased our projected benefit obligation by approximately $51.5 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we increased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 5.06% and decreased our assumption on the NorthWestern Corporation Pension Plan to 4.23% for 2019.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2018	2017	2016	2018	2017	2016
Discount rate	4.15-4.20 %	3.50-3.60 %	3.95-4.10 %	3.90-3.95 %	3.20-3.30 %	3.40-3.55 %
Expected rate of return on assets	4.47-4.97	4.70	5.80	4.82	4.70	5.80
Long-term rate of increase in compensation levels (nonunion)	2.84	2.89	3.28	2.84	2.89	3.28
Long-term rate of increase in compensation levels (union)	2.03	2.03	3.20	2.03	2.03	3.20
Interest crediting rate	4.00-6.00	4.00-6.00	4.20-6.00	N/A	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00% fixed rate. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially invested as long-term cash holdings reduce long-term rates of return;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5%, is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2018	2017	2018	2017	2018	2017
Domestic debt securities	55.0%	55.0%	75.0%	70.0%	40.0%	40.0%
International debt securities	4.0	4.0	2.5	2.5	—	—
Domestic equity securities	16.5	16.5	9.0	11.0	50.0	50.0
International equity securities	24.5	24.5	13.5	16.5	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2018	2017	2018	2017	2018	2017
Cash and cash equivalents	0.1%	0.1%	—%	—%	1.0%	1.5%
Domestic debt securities	57.5	54.5	81.3	70.0	40.8	35.2
International debt securities	4.4	4.0	2.6	2.5	—	—
Domestic equity securities	15.0	16.7	6.3	11.1	49.1	53.4
International equity securities	23.0	24.7	9.8	16.4	9.1	9.9
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. and international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. We also invest in international equities with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company’s net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT’s investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT’s investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. We expect to continue to make contributions to the pension plans in 2019 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension expense for 2018, 2017 and 2016 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2018	2017	2016
NorthWestern Energy Pension Plan (MT)	$ 8,000	$ 8,000	$ 11,500
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200	1,200
	$ 9,200	$ 9,200	$ 12,700

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2019	$ 32,618	$ 3,208
2020	33,880	2,785
2021	35,391	2,731
2022	36,726	2,432
2023	38,124	2,186
2024-2028	206,071	6,606

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2018, 2017 and 2016 were $10.6 million, $10.0 million, and $9.8 million.

(16) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. In 2014, an additional 600,000 shares of common stock were authorized by the shareholders for issuance under the ECP. As of December 31, 2018, there were 751,071 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Performance Unit Awards

Performance unit awards are granted annually under the ECP. These awards vest at the end of the three-year performance period if we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both market- and performance-based components. The performance goals are independent of each other and equally weighted, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance unit awards. The fair value of the earnings per share component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2018	2017
Risk-free interest rate	2.30%	1.50%
Expected life, in years	3	3
Expected volatility	16.5% to 21.9%	17.0% to 22.7%
Dividend yield	4.2%	3.7%

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2018, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	175,468	$ 49.11
Granted	110,164	47.99
Vested	(83,276)	50.32
Forfeited	(4,653)	48.65
Remaining nonvested grants	197,703	$ 47.99

We recognized compensation expense of $6.3 million, $3.9 million, and $5.3 million for the years ended December 31, 2018, 2017, and 2016, respectively, and a related income tax expense of $0.3 million, $0.4 million, and $1.8 million for the years ended December 31, 2018, 2017, and 2016, respectively. As of December 31, 2018, we had $2.0 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statements of Common Shareholders' Equity. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $4.2 million, $3.7 million, and $3.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2018, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	67,540	$ 45.05
Granted	15,916	54.21
Vested	(8,496)	35.14
Forfeited	(1,569)	44.46
Remaining nonvested grants	73,391	$ 48.19

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2018, 2017 and 2016, DSUs issued to members of our Board totaled 29,870, 54,920 and 28,338, respectively. During 2018, DSUs withdrawn by our Board totaled 136,640. Total compensation expense attributable to the DSUs during the years ended December 31, 2018, 2017 and 2016 was approximately $1.9 million, $2.9 million and $2.4 million, respectively. During 2018, DSUs of $8.2 million were withdrawn.

(17) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,865,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 16 - Stock-Based Compensation.

In September 2017, we entered into an Equity Distribution Agreement with Merrill Lynch, Pierce, Fenner, & Smith, Incorporated and J. P. Morgan Securities LLC, collectively the sales agents, pursuant to which we offered and sold shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. We concluded this program during the second quarter of 2018. During 2018, we issued 835,765 shares of our common stock at an average price of $54.45, for net proceeds of $44.9 million. Since inception of the program, we sold 1,724,703 shares of our common stock at an average price of $57.98 per share. Net proceeds received were approximately $98.5 million, which are net of sales commissions and other fees paid of approximately $1.4 million.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 12,193 and 34,208 during the years ended December 31, 2018 and 2017, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(18) 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:

	December 31,		
	2018	2017	2016
Basic computation	49,984,562	48,557,599	48,298,896
Dilutive effect of			
Performance and restricted share awards (1)	252,909	97,722	176,166
Diluted computation	50,237,471	48,655,321	48,475,062

(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.

We adopted the provisions of ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, during the fourth quarter of 2016. Under this ASU, the assumed proceeds from applying the treasury stock method when computing earnings per share no longer includes the amount of excess tax benefits or deficiencies that used to be recognized as additional paid-in capital. This change in the treasury stock method was made on a prospective basis, with adjustments reflected as of January 1, 2016. The changes to the treasury stock method required by this ASU increased dilutive shares by 22,044 shares for the year ended December 31, 2016.

(19) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. These contracts require us to purchase minimum amounts of energy at prices ranging from $63 to $136 per MWH through 2029. As of December 31, 2018, our estimated gross contractual obligation related to these contracts is approximately $709.8 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $567.2 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within cost of sales and electric revenues in our Consolidated Statements of Income. The present value of the remaining liability is recorded in other noncurrent liabilities in our Consolidated Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2018	2017
Beginning QF liability	$ 132,786	$ 134,324
Unrecovered amount [1]	(39,827)	(12,009)
Interest expense	9,301	10,471
Ending QF liability	$ 102,260	$ 132,786

[1] The unrecovered amount includes (i) a periodic adjustment of the liability for price escalation, which was less than modeled, resulting in a liability reduction of $17.5 million and (ii) the annual reset to actual output and pricing resulting in approximately $7.6 million in lower QF supply costs due to outages at two facilities.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2019	$ 75,278	$ 59,020	$ 16,258
2020	77,319	59,647	17,672
2021	79,166	60,136	19,030
2022	81,060	60,639	20,421
2023	83,178	61,280	21,898
Thereafter	313,794	266,493	47,301
Total	$ 709,795	$ 567,215	$ 142,580

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 25 years. Costs incurred under these contracts are included in Cost of Sales in the Consolidated Statements of Income and were approximately $209.3 million, $228.4 million and $216.8 million for the years ended December 31, 2018, 2017, and 2016, respectively. As of December 31, 2018, our commitments under these contracts are $197.0 million in 2019, $149.6 million in 2020, $124.3 million in 2021, $126.9 million in 2022, $122.1 million in 2023, and $1.3 billion thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $18.0 million between 2019 and 2040. These commitments are not reflected in our Consolidated Financial Statements.

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 $26.6 million to $34.6 million. As of December 31, 2018, we have a reserve of approximately $29.7 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 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 $22.5 million of our environmental reserve accrual is related to manufactured gas plants. 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 December 31, 2018, the reserve for remediation costs at this site is approximately $8.4 million, and we estimate that approximately $3.7 million of this amount will be incurred during the next five years.

We also 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.

In addition, 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 January 2019, we submitted a revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments on a previously submitted draft RIWP. The revised RIWP requires additional investigation including vapor intrusion and potential contamination from transformers and treated poles. MDEQ is expected to complete its review by the second quarter of 2019.

An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. Monitoring wells have been installed and groundwater is monitored semiannually. At the request of Missoula Valley Water Quality District (MVWQD), a draft risk assessment was prepared for the Missoula site and presented to the MVWQD. We and the MVWQD agreed additional site investigation work is appropriate. Analytical results from an October 2016 sampling exceeded the Montana Maximum Contaminant Level for benzene and/or total cyanide in certain monitoring wells. These results were forwarded to MVWQD which shared the same with the MDEQ. MDEQ requested that MVWQD file a formal complaint with MDEQ's Enforcement Division, which MVWQD filed in July 2017. This is expected to prompt MDEQ to reevaluate its position concerning listing the Missoula site on the State of Montana's superfund list. New landowners purchased a portion of the Missoula site using funding provided by a third party. The terms of the funding require the new landowners to address environmental issues. The new landowners contacted us and we addressed their immediate concerns. After researching historical ownership we have identified another potentially responsible party with whom we have initiated communications regarding the 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 GHG including, most significantly, CO_2. These actions include legislative proposals, Executive and EPA actions at the federal level, actions at the state level, 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, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of Federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict the timing or form of any potential legislation. In the absence of such legislation, EPA is presently regulating new and existing sources of GHG emissions through regulations. EPA is currently reviewing its existing regulations as a result of an Executive Order issued by President Trump on March 28, 2017 (the Executive Order) instructing all federal agencies to review all regulations and other policies (specifically including the CPP, which is discussed in further detail below) that burden the development or use of domestically produced energy resources and suspend, revise or rescind those that pose an undue burden beyond that required to protect the public interest.

The CPP was published in October 2015 and was intended to establish GHG performance standards for existing power plants under Clean Air Act Section 111(d). The CPP established CO_2 emission performance standards for existing electric utility steam generating units and natural gas combined cycle units. As a result of the Executive Order review, on October 10, 2017, the EPA proposed to repeal the CPP. In addition, petitions for review and reconsideration of the CPP were filed by numerous parties, including us. Those proceedings are currently being held in abeyance, at the request of the EPA, in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) pending implementation of the Executive Order.

On August 31, 2018, EPA published the proposed ACE, intended to serve as a replacement for the CPP. If finalized as proposed, it is expected that the ACE would generally require a lower level of CO_2 emission reductions than the CPP and provide more regulatory flexibility to individual states.

We cannot predict whether the CPP will be repealed or whether the ACE will be implemented in its current form. In addition, it is unclear how pending or future litigation relating to GHG matters, including the actions pending in the D.C. Circuit, will impact us. If GHG regulations are implemented, it would 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. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impact customers in our region.

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

Clean Air Act Rules and Associated Emission Control Equipment Expenditures **-** The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act that could require the installation of emission control equipment at the generation plants in which we have joint ownership.

On January 10, 2017, the EPA published amendments to the requirements under the Clean Air Act for state plans for protection of visibility. 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. Therefore, by 2021, Montana, or EPA, must develop 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 EPA's request to hold the case in abeyance while EPA considers further administrative action to revisit the rule.

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 CPP and ACE proposals, as discussed above, we cannot predict the impact of the CPP on us until there is a definitive judicial decision or administrative action by the EPA

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 it in early 2016 to purchase the output from these 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 various 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 executed four power purchase agreements with PNWS as of that date, we had not entered into any interconnection agreements with it for those projects. As a result, none of PNWS' Montana projects 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 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.

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. The MPSC, however, 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. We subsequently filed a motion to dismiss and a motion for partial summary judgment, and PNWS filed a motion for summary judgment on its request for declaratory relief regarding those four power purchase agreements. The United States District Court denied all of those motions in August of 2018.

Discovery concluded in November 2018, and we subsequently filed additional dispositive pre-trial motions which are pending. PNWS has requested leave to renew its prior Motion for Summary Judgment on Count VI of its lawsuit, which seeks a judicial declaration that the four power purchase agreements in question are valid and enforceable. The Court has not yet ruled on that request. PNWS is currently seeking approximately $8 million in damages. We participated in an unsuccessful mediation on January 24, 2019. We dispute the remaining claims in PNWS' lawsuit and will continue to vigorously defend against them. We cannot currently predict an outcome or estimate the amount or range of loss that would result from an adverse outcome in the litigation. We anticipate that any breach of contract damages awarded would be borne by us. If the United States District Court determines that we must purchase power from PNWS at the QF-1 Tariff Rate that was in effect prior to June 16, 2016, we anticipate seeking to recover those costs in rates from customers, subject to the terms of the final PCCAM Order.

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 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, which culminated with a 2012 decision by the United States Supreme Court 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 between Black Eagle Falls and the Great Falls. In particular the dismissal pertains to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. This leaves a portion of the Black Eagle reservoir and Morony Dam and reservoir at issue. While the dismissal of these four facilities is subject to appeal, that appeal would not likely occur until after judgment in the case. We and Talen filed our respective answers to the State's Complaint on August 22, 2018. Additionally, we and Talen filed a motion to join the United States as a defendant to the litigation. The motion is fully briefed and the Federal District Court heard oral arguments on February 8, 2019. A decision on the joinder motion is expected to follow.

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.

Wilde Litigation

In October 2017, Martin Wilde, a Montana resident and wind developer, and three entities with which he is affiliated, commenced a lawsuit against the MPSC, each individual commissioner of the MPSC (in each of their official and individual capacities), and NorthWestern in the Montana Eighth Judicial District Court (Eighth District Court). The plaintiffs allege that the MPSC collaborated with NorthWestern to set discriminatory rates and contract durations for QF developers. The plaintiffs seek power purchase agreements at $45.19 per megawatt hour for a 25-year term or, as an alternative remedy to the alleged discrimination, a reduction in NorthWestern's rates by $17.03 per megawatt hour. The plaintiffs also seek compensatory damages of not less than $4.8 million, various forms of declaratory relief, injunctive relief, unspecified damages, and punitive damages.

Mr. Wilde died in a farming accident in November 2017 and the plaintiffs requested a stay of the proceeding. The Eighth District Court lifted the stay on January 11, 2019. Both NorthWestern and the MPSC have filed motions for summary judgment, which the Court heard on February 1, 2019. We are awaiting a decision on the motions.

We dispute the claims in the lawsuit and intend to vigorously defend those claims. This matter is in the initial stages, and we cannot predict an outcome or estimate the amount or range of loss that would result from an adverse outcome in the remaining claims.

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.

(20) Revenue from Contracts with Customers

Accounting Policy

Our revenues are primarily from tariff based sales. We provide gas and/or electricity to customers under these tariffs without a defined contractual term (at-will). As the revenue from these arrangements is equivalent to the electricity or gas supplied and billed in that period (including estimated billings), there will not be a shift in the timing or pattern of revenue recognition for such sales. We have also completed the evaluation of our other revenue streams, including those tied to longer term contractual commitments. These revenue streams have performance obligations that are satisfied at a point in time, and do not have a shift in the timing or pattern of revenue recognition.

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers, but not yet billed at month-end.

Nature of Goods and Services

We currently provide retail electric and natural gas services to three primary customer classes. Our largest customer class consists of residential customers, which 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 our 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 in 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 our 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 in 20-30 days after the billing date.

Disaggregation of Revenue

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

	Twelve Months Ended December 31, 2018		
	Electric	**Natural Gas**	**Total**
Montana	$ 287.3	$ 102.7	$ 390.0
South Dakota	64.2	25.4	89.6
Nebraska	—	23.4	23.4
Residential	**351.5**	**151.5**	**503.0**
Montana	329.6	51.7	$ 381.3
South Dakota	94.0	18.0	112.0
Nebraska	—	11.9	11.9
Commercial	**423.6**	**81.6**	**505.2**
Industrial	42.6	1.2	43.8
Lighting, Governmental, Irrigation, and Interdepartmental	29.6	1.0	30.6
Total Customer Revenues	**847.3**	**235.3**	**1,082.6**
Other Tariff and Contract Based Revenues	65.4	39.2	104.6
Total Revenue from Contracts with Customers	**912.7**	**274.5**	**1,187.2**
Regulatory amortization	8.4	(3.6)	4.8
Total Revenues	**$ 921.1**	**$ 270.9**	**$ 1,192.0**

(21) Segment and Related 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 for the twelve months ended are as follows (in thousands):

December 31, 2018	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 921,093	$ 270,916	$ —	$ —	$ 1,192,009
Cost of sales	194,608	78,275	—	—	272,883
Gross margin	726,485	192,641	—	—	919,126
Operating, general and administrative	223,598	82,864	657	—	307,119
Property and other taxes	134,681	36,569	9	—	171,259
Depreciation and depletion	144,636	29,822	18	—	174,476
Operating income (loss)	223,570	43,386	(684)	—	266,272
Interest expense, net	(79,033)	(5,858)	(7,097)	—	(91,988)
Other income, net	2,794	962	210	—	3,966
Income tax benefit (expense)	21,686	9,268	(12,244)	—	18,710
Net income (loss)	$ 169,017	$ 47,758	$ (19,815)	$ —	$ 196,960
Total assets	$ 4,512,392	$ 1,127,252	$ 4,732	$ —	$ 5,644,376
Capital expenditures	$ 221,968	$ 61,998	$ —	$ —	$ 283,966

December 31, 2017	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 1,037,053	$ 268,599	$ —	$ —	$ 1,305,652
Cost of sales	334,029	76,320	—	—	410,349
Gross margin	703,024	192,279	—	—	895,303
Operating, general and administrative (1)	216,003	78,757	43	—	294,803
Property and other taxes	127,391	35,214	9	—	162,614
Depreciation and depletion	136,556	29,548	33	—	166,137
Operating income (loss)	223,074	48,760	(85)	—	271,749
Interest expense, net	(82,454)	(5,920)	(3,889)	—	(92,263)
Other (loss) income, net (1)	(3,487)	(878)	950	—	(3,415)
Income tax (expense) benefit	(7,424)	(6,684)	740	—	(13,368)
Net income (loss)	$ 129,709	$ 35,278	$ (2,284)	$ —	$ 162,703
Total assets	$ 4,346,484	$ 1,071,847	$ 2,586	$ —	$ 5,420,917
Capital expenditures	$ 226,077	$ 50,361	$ —	$ —	$ 276,438

December 31, 2016	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 1,011,595	$ 245,652	$ —	$ —	$ 1,257,247
Cost of sales	332,817	68,156	—	—	400,973
Gross margin	678,778	177,496	—	—	856,274
Operating, general and administrative (1)	210,523	83,896	(556)	—	293,863
Property and other taxes	115,583	32,505	10	—	148,098
Depreciation and depletion	130,236	29,067	33	—	159,336
Operating income	222,436	32,028	513	—	254,977
Interest expense, net	(86,038)	(6,589)	(2,343)	—	(94,970)
Other (loss) income, net (1)	(2,967)	(1,488)	973	—	(3,482)
Income tax benefit (expense)	7,392	(1,687)	1,942	—	7,647
Net income	$ 140,823	$ 22,264	$ 1,085	$ —	$ 164,172
Total assets	$ 4,363,848	$ 1,129,355	$ 6,118	$ —	$ 5,499,321
Capital expenditures	$ 236,014	$ 51,887	$ —	$ —	$ 287,901

(1) We adopted ASU 2017-07 on January 1, 2018. As a result, we recorded the non-service cost component of net periodic benefit cost within other income (expense), net. We adopted this standard retrospectively and \$7.5 million and \$2.9 million, respectively, were reclassified from electric and gas operating, general and administrative expenses to other income (expense), net for the twelve months ended December 31, 2017, to conform to current period presentation. For the twelve months ended December 31, 2016, \$6.2 million and \$2.8 million respectively, were reclassified from electric and gas operating, general and administrative expenses to other income (expense), net.

(22) Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Our business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations. Amounts presented are in thousands, except per share data:

2018	First	Second	Third	Fourth
Operating revenues	$ 341,502	$ 261,817	$ 279,874	$ 308,816
Operating income	84,512	69,210	47,808	64,742
Net income	$ 58,499	$ 43,787	$ 28,182	$ 66,492
Average common shares outstanding	49,416	49,869	50,318	50,321
Income per average common share:				
Basic	$ 1.18	$ 0.88	$ 0.56	$ 1.32
Diluted	$ 1.18	$ 0.87	$ 0.56	$ 1.31

2017	First	Second	Third	Fourth
Operating revenues	$ 367,312	$ 283,859	$ 309,933	$ 344,548
Operating income [(1)]	87,772	46,282	64,120	73,575
Net income	$ 56,567	$ 21,830	$ 36,412	$ 47,894
Average common shares outstanding	48,386	48,451	48,487	48,902
Income per average common share:				
Basic	$ 1.17	$ 0.45	$ 0.75	$ 0.98
Diluted	$ 1.17	$ 0.44	$ 0.75	$ 0.98

[(1)] We adopted ASU 2017-07 on January 1, 2018. As a result, we reclassified the non-service cost component of net periodic benefit cost from operating, general and administrative expenses to other income (expense), net. This resulted in a $2.6 million increase in operating income during each quarter of 2017.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS

NORTHWESTERN CORPORATION AND SUBSIDIARIES

Column A	Column B	Column C	Column D	Column E
	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance End of Period
Description		(in thousands)		
FOR THE YEAR ENDED DECEMBER 31, 2018				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	$ 2,860	$ 3,369	$ (3,949)	$ 2,280
FOR THE YEAR ENDED DECEMBER 31, 2017				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	2,948	3,166	(3,254)	2,860
FOR THE YEAR ENDED DECEMBER 31, 2016				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	3,999	1,307	(2,358)	2,948