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, 2017

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 and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for shorter period that the registrant was required to submit and post 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 ☐ (Do not check if smaller reporting company)	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 $2,957,686,000 computed using the last sales price of $61.02 per share of the registrant's common stock on June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter.

As of February 9, 2018, 49,397,196 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 2018 Annual Meeting of Shareholders are incorporated by reference into Part III of this Form 10-K

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 Securities and Exchange Commission (SEC) on Forms 10-K, 10-Q and 8-K and Proxy Statements on Schedule 14A.

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

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.

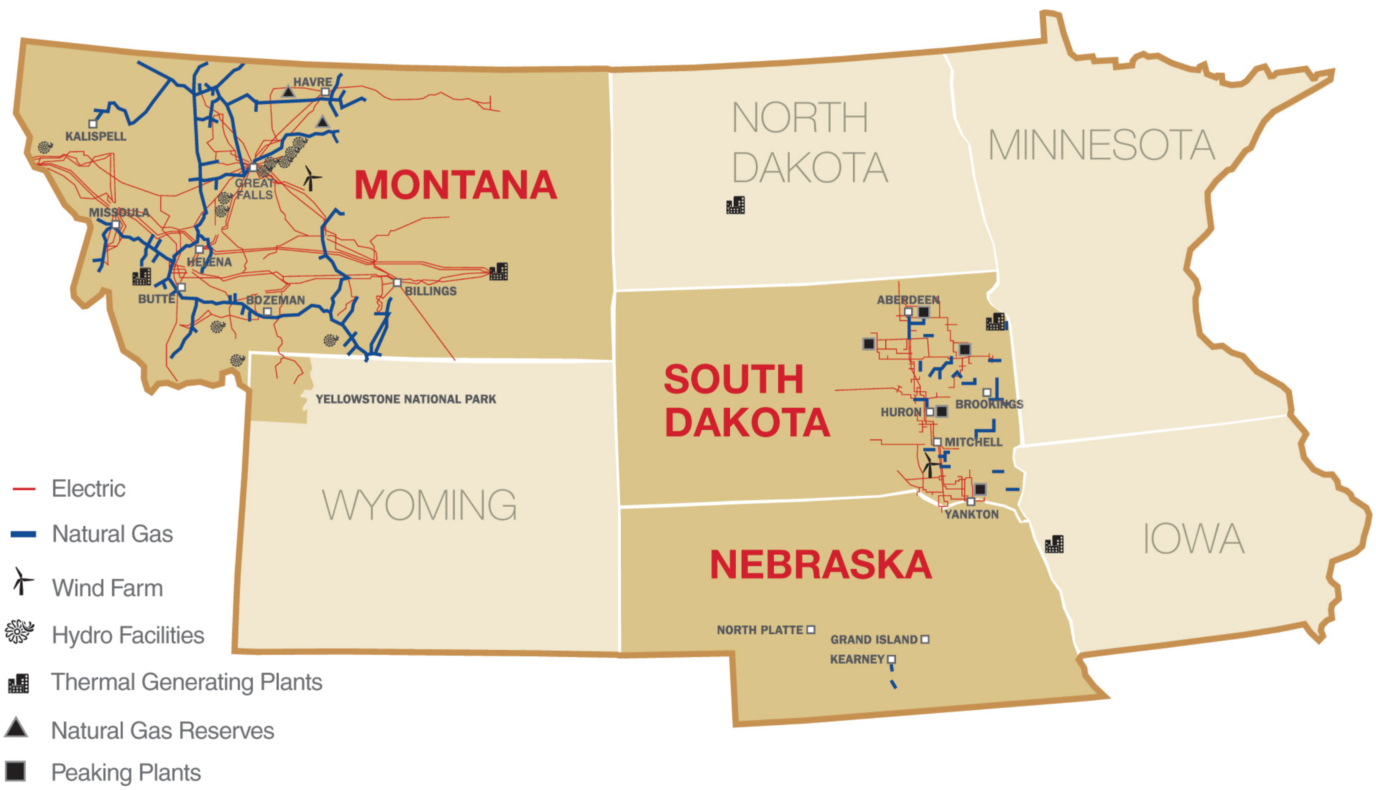
ITEM 1. BUSINESS

OVERVIEW

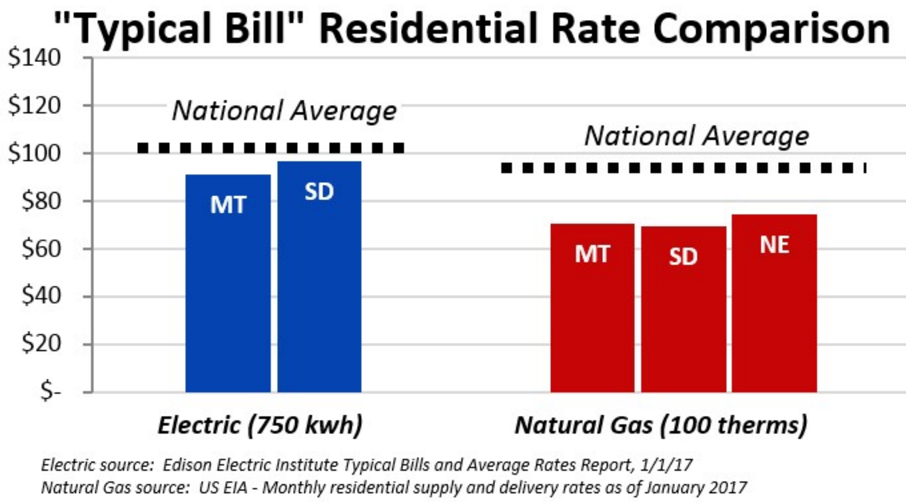
NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 718,300 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

We operate our business in the following reporting segments:

- Electric operations;
- Natural gas operations;
- All other, which primarily consists of unallocated corporate costs.

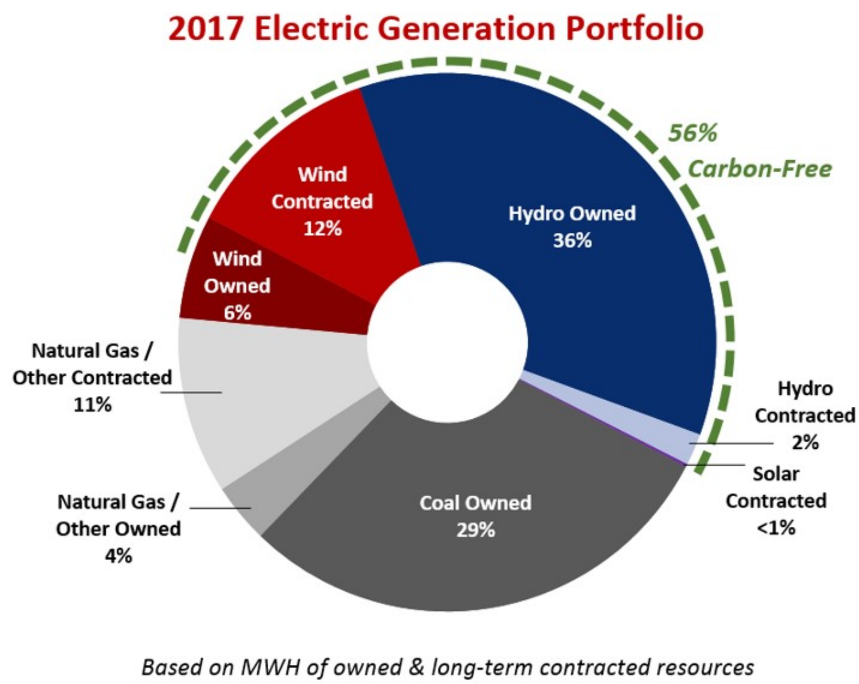


We seek to deliver value to our customers by providing high reliability and customer service, an environmentally sustainable generation mix and a typical residential customer bill that is below the national average benchmark.



Environmental Stewardship

We strive to balance statutory 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. Our policies support both the role of cost-effective energy efficiency and the potential value of low or carbon-free resources as part of our diverse supply portfolio. In 2017, approximately 56% of our retail needs originated from carbon-free resources.



ELECTRIC OPERATIONS

Montana

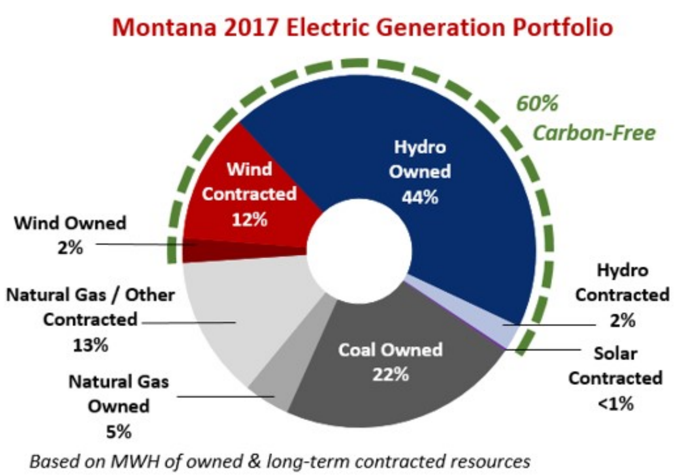
Our regulated electric utility business in Montana includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73% of Montana's land area, and includes a 2016 census estimated population of approximately 913,900. During 2017, we delivered electricity to approximately 369,100 customers in 208 communities and their surrounding rural areas, 11 rural electric cooperatives and, in Wyoming, to the Yellowstone National Park. In 2017, 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 1,803 MWs on July 13, 2017. Our control area average demand for 2017 was approximately 1,276 MWs per hour, with total energy delivered of more than 11.1 million MWHs.

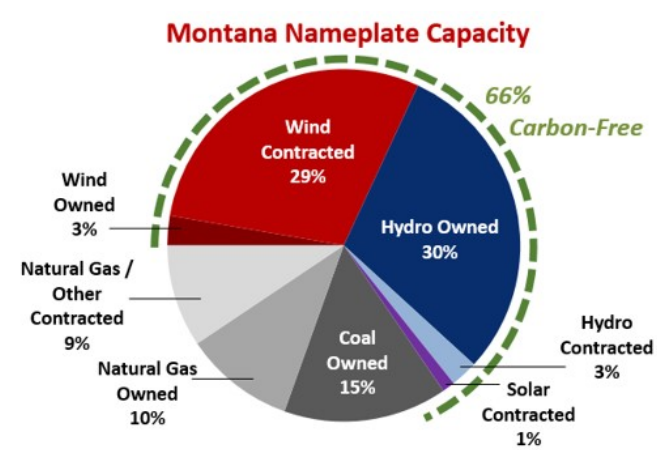
Our Montana electric transmission and distribution network consists of approximately 24,660 miles of overhead and underground transmission and distribution lines and 385 transmission and distribution substations. Our transmission system is directly interconnected with Avista Corporation; Idaho Power 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 future energy needs. We filed a biennial Electric Supply Resource Procurement Plan (resource plan) with the MPSC during 2016, which guides resource acquisition activities. We have significant generation capacity deficits and negative reserve margins, and our 2016 resource plan identified price and reliability risks to our customers if we rely solely upon market purchases to address these capacity needs. In addition to our responsibility to meet peak demand, national reliability standards effective July 2016 require us to have even 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. We expect to file our next resource plan in late 2018.

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.





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 60% of our retail load requirements for 2017. We expect that approximately 60% of our retail obligations will be met by owned generation in 2018 as well. In addition, QFs provide a total of 393 MWs of nameplate capacity, including 87 MWs of capacity from waste petroleum coke and waste coal, 273 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 2018, 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.

Generation Facilities

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

Hydro Facilities	COD	River Source	FERC License Expiration	Net Capacity (MW) (1)
Black Eagle	1927	Missouri	2040	21
Cochrane	1958	Missouri	2040	69
Hauser	1911	Missouri	2040	19
Holter	1918	Missouri	2040	48
Madison	1906	Madison	2040	8
Morony	1930	Missouri	2040	48
Mystic	1925	West Rosebud Creek	2050	12
Rainbow	1910/2013	Missouri	2040	60
Ryan	1915	Missouri	2040	63
Thompson Falls	1915	Clark Fork	2025	94
Total				**442**

(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	Namplate Capacity (MW)	Ownership Interest	Owned Capacity (MW)
Colstrip Unit 4, located near Colstrip in southeastern Montana	Sub-bituminous coal	740	30%	222
Dave Gates Generating Station, located near Anaconda, Montana	Natural Gas	150	100%	150
Spion Kop Wind, located in Judith Basin County in Montana	Wind	40	100%	40

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 risk 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, and contingency reserves. DGGS also provided approximately 7 MWs of retail base-load requirements in 2017.

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.

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. Our owned hydro generation assets are not eligible resources under the RPS. 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, 2017, approximately 65 MW of community renewable energy projects (CREP), if cost effective. Since 2008, we have undertaken competitive solicitations to acquire this particular resource but have only contracted for 25 MW. We filed waivers for 2012 through 2016, as we have not been able to contract with projects that meet the required qualifications. The MPSC granted waivers for 2012 through 2014, and the waiver requests for 2015 and 2016 are still pending. We expect to file a waiver request for 2017. If the requested waivers are not granted, we may be liable for penalties. 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

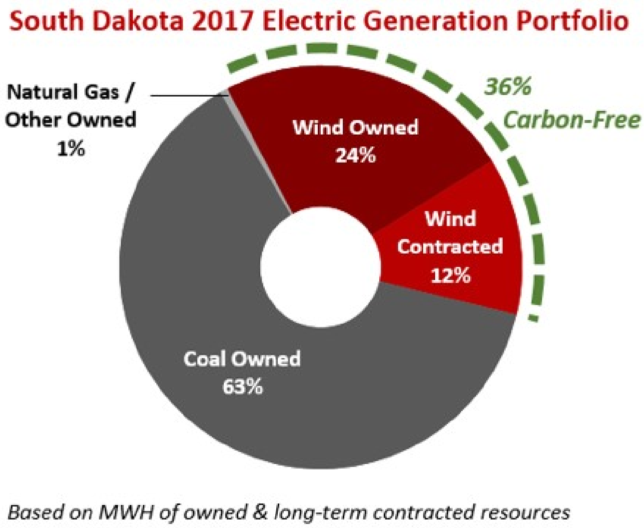
Our South Dakota electric utility business operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties with a combined 2010 census population of approximately 226,200. We provide retail electricity to more than 63,600 customers in 110 communities in South Dakota. In 2017, by category, residential, commercial and other sales accounted for approximately 39%, 59%, and 2%, respectively, of our South Dakota retail electric utility revenue. Peak demand was approximately 330 MWs, the average load was approximately 186 MWs, and 1.63 million MWHs were supplied during the year ended December 31, 2017.

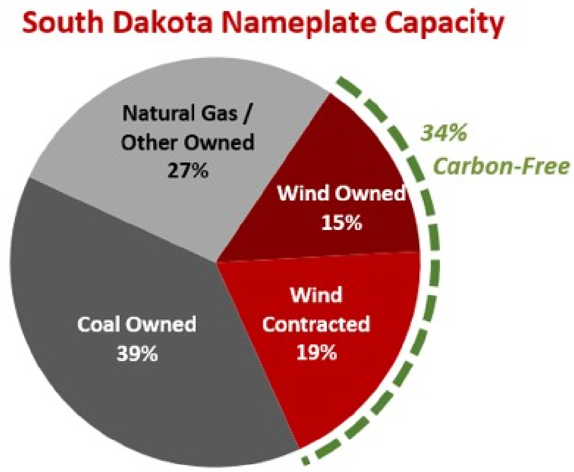
Our transmission and distribution network in South Dakota consists of approximately 3,560 miles of overhead and underground transmission and distribution lines as well as 126 substations. We have interconnection with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; 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 use market purchases and peaking generation to provide peak supply in excess of our base-load capacity. We have an agreement with Missouri River Energy Services to supply firm capacity of 35 MW in 2018. 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.

Our sources of energy by type during 2017 were as follows:





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 upon 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 three wind projects. 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 two wind projects, one of which is a QF, 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.

South Dakota has a voluntary renewable and recycled energy objective, which provides that 10% of all electricity sold at retail within South Dakota be obtained from renewable and recycled energy sources. In 2017, approximately 29% of South Dakota retail needs originated from renewable resources. In 2018, we expect to continue to receive approximately the same level of generation from renewable resources. We may sell company-generated RECs, with proceeds benefiting our customers. We also do not purchase all of the RECs associated with contracted wind generation. Accordingly, not all of the energy from these resources delivered to retail customers qualifies as renewable or recycled under this voluntary standard.

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 330 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. Marketing activities in SPP are handled for us by a third-party provider acting as our agent. Along with operating the transmission system, SPP also coordinates transmission planning for all members of the organization.

NATURAL GAS OPERATIONS

Montana

Our regulated natural gas utility business in Montana includes production, storage, transmission and distribution. During 2017, we distributed natural gas to approximately 196,700 customers in 118 Montana communities over a system that consists of approximately 5,187 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 42.9 Bcf during the year ended December 31, 2017.

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 more than 140 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, 2017, were approximately 20.8 Bcf. Our Montana natural gas supply requirements for electric generation fuel for the year ended December 31, 2017, were approximately 3.9 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 Rockies (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, 2017, these owned reserves totaled approximately 55.9 Bcf and are estimated to provide approximately 4.5 Bcf in 2018, or about 22 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 88,900 customers in 59 South Dakota communities and three Nebraska communities. We have approximately 2,416 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 eight 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 27.4 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 3.3 Bcf of third-party transportation volume on our Nebraska distribution system during 2017.

Our South Dakota natural gas supply requirements for the year ended December 31, 2017, were approximately 5.6 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, 2017, were approximately 4.1 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 an additional 10-year term 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, five of our Montana franchises are scheduled to reach the end of their fixed term, which account for approximately 39,000 or 20 percent of our Montana natural gas customers. Eight of our South Dakota franchises and one franchise in Nebraska, which account for approximately 18,550 or 21% 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 3 - 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	$1,163.4	7.92%	10.25%	48%
Montana - DGGS (3)	January 2011	172.7	122.5	8.16%	10.25%	50%
Montana - Colstrip Unit 4	January 2009	400.4	298.7	8.25%	10.00%	50%
Montana Spion Kop	December 2012	69.8	47.1	7.00%	10.00%	48%
Montana hydro assets	November 2014	841.8	783.4	6.91%	9.80%	48%
Montana natural gas delivery and production	September 2017	430.2	435.2	6.96%	9.55%	46.79%
South Dakota electric (4)	December 2015	557.3	577.6	7.24%	n/a	n/a
South Dakota natural gas (4)	December 2011	65.9	63.0	7.80%	n/a	n/a
Nebraska natural gas (4)	December 2007	24.3	27.5	8.49%	10.40%	n/a
		$3,194.9	$3,518.4			

(1) Rate base reflects amounts on which we are authorized to earn a return.
(2) Rate base amounts are estimated as of December 31, 2017.
(3) 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 - In April 2017, the Montana legislature passed House Bill 193 (HB 193), amending the statute that provided for mandatory recovery of our prudently incurred electric supply costs effective July 1, 2017. The revised statute gives the MPSC discretion whether to approve an electric supply cost adjustment mechanism. The MPSC initiated a process to develop a replacement electric supply cost adjustment mechanism, and in response, in July 2017, we filed a proposed electric Power Cost and Credit Adjustment Mechanism (PCCAM). A hearing is scheduled to begin May 31, 2018.

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 an 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 also defines the terms, conditions and rates of our Montana transmission service, including ancillary services. Our South Dakota transmission operations are in the SPP and the majority of transmission service is provided under the SPP OATT. We maintain an OATT in South Dakota to provide discrete transmission service to a small number of transmission customers.

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, but

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.

SEASONALITY AND CYCLICALITY

Our electric and gas utility businesses are seasonal businesses, 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. Demand for electricity is often greater in the summer and winter months for cooling and heating, respectively. Accordingly, our operations have historically generated less revenue and income when weather conditions are milder in the winter and cooler in the summer. These weather patterns could adversely affect our results of operations, financial condition and liquidity.

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 18 - 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, 2017, we had 1,557 employees. Of these, 1,233 employees were in Montana and 324 were in South Dakota or Nebraska. Of our Montana employees, 459 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. Of our South Dakota and Nebraska employees, 194 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. 9, 2018
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).	62
Brian B. Bird	Vice President and 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.	55
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.	55
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).	62
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).	59
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.	39
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.	53
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.	49

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. 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. Historically, our wholesale costs for electricity and natural gas supply were recovered through various pass-through cost tracking mechanisms in each of the states we serve.

Montana

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

- In January 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. This results in a lower property tax allocation to our Montana electric retail customers and a higher property tax allocation to FERC transmission customers (we do not have a property tax tracker for FERC jurisdictional purposes).

- 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 substantially lowering the rate for future QF contracts. In this order, the MPSC also applied the 15-year contract term to our future owned and contracted electric supply resources. As a result, we terminated our competitive solicitation process to determine the lowest-cost / least-risk approach for addressing our intermittent capacity and reserve margin needs in Montana. This order may have a significant impact on our approach to meet our portfolio needs. We continue to evaluate the impact of this decision.

- In 2016, the MPSC disallowed replacement power costs from a 2013 outage at Colstrip Unit 4 requested in our electric tracker filings. We appealed the MPSC's decision regarding the disallowance of Colstrip Unit 4 costs in Montana District Court, arguing that these decisions were arbitrary and capricious, and violated Montana law.

- In October 2015, the MPSC issued an order eliminating the lost revenue adjustment mechanism. This mechanism was established in 2005 as a component of an approved energy efficiency program, by which we recovered on an after-the-fact basis our fixed costs that would otherwise have been collected in the kWh sales lost due to energy efficiency programs through our supply tracker. Recovery of lost revenues was terminated, prospectively, effective December 1, 2015.

- In October 2013, the MPSC concluded that costs associated with a 2012 outage at DGGS were imprudently incurred, and disallowed recovery.

We have two significant dockets currently in process with the MPSC. The MPSC advocated revising the statute that provided for mandatory recovery of our prudently incurred electric supply costs, and in April 2017, the Montana legislature passed HB 193, amending the statute. In July 2017, we filed a proposed electric PCCAM. Following the submission of intervenor testimony, the MPSC identified additional issues and established a revised procedural schedule with a hearing scheduled to begin May 31, 2018. We cannot guarantee how the MPSC may apply the statute in establishing a revised mechanism. To the extent our energy supply costs are deemed imprudent by the applicable state regulatory commissions, or the passage of HB 193 reduces our recovery or the timeliness of cash flows, the revised mechanism could adversely impact our results of operations and cash flows. The MPSC also established a docket regarding the impact of the Tax Cuts and Jobs Act and we expect to submit a filing regarding the customer benefit during the first quarter of 2018. We cannot predict how the MPSC may address this filing.

FERC & Other Regulation

In our regulatory filings related to DGGS, we proposed an allocation of approximately 80% of costs to retail customers subject to the MPSC's jurisdiction and approximately 20% allocated to wholesale customers subject to FERC's jurisdiction. In March 2012, the MPSC's final order approved using our proposed cost allocation methodology, but requires us to complete a study of the relative contribution of retail and wholesale customers to regulation capacity needs. The results of this study may be used in determining future cost allocations between retail and wholesale customers. However, there is no assurance that both the MPSC and FERC will agree on the results of this study, which could result in an inability to fully recover our costs in a future electric general rate filing.

We must also comply with established reliability standards and requirements, which apply to the NERC functions in both the MRO for our South Dakota operations and WECC for our Montana operations. The FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity that violates their rules, regulations or standards. Violations may be discovered through various means, including self-certification, self-reporting, compliance investigations, audits, periodic data submissions, exception reporting, and complaints. 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.

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.

Our ability to invest in additional generation is impacted by PURPA, which requires electric utilities, with few exceptions, to purchase energy and capacity from independent power producers that are QFs. Our 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.

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.

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 believe that we are in compliance with environmental regulatory requirements; however, possible future developments, such as more stringent environmental laws and regulations, and the timing of future enforcement proceedings that may be taken by environmental authorities, 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, and in December 2017, issued an Advance Notice of Proposed Rulemaking (ANPR), soliciting information on systems of emission reduction that comply with EPA's interpretation of the Clean Air Act, for a possible replacement of the CPP. In light of the proposed repeal, and the ANPR, the future of the CPP regulations and associated guidance is uncertain. However, if the CPP is not repealed, survives the pending legal challenges and is implemented as written or if a replacement to the CPP is adopted with similar requirements, it could result in significant additional compliance costs that would affect our future results of operations and financial position if such costs are not recovered through regulated rates. Due to the pending litigation, the proposed repeal of the CPP, the ANPR, and the uncertainties in the state approaches, the ultimate timing and impact of the CPP or other GHG regulations on our operations cannot be determined with certainty at this time. 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.

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, wildfires, 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 wildfires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, wildfires 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 wildfires could negatively impact our financial condition, results of operations or cash flows.

There is also a concern that the physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate. Extreme weather conditions creating high energy demand on our own and/or other systems may raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks.

Our 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 increasing rates generally and increasing rates for customers who do not own generation, unless retail rates are designed to share the costs of the distribution grid across all customers that 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 efficiency 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 and the availability of generation, 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.

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.

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. These 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 cyber attacks and other disruptive activities on third party facilities that are interconnected to us through the regional transmission grid or natural gas pipeline infrastructure. 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.

We rely on information technology networks and systems to operate our critical infrastructure, engage in asset management activities, and process, transmit and store electronic information including customer and employee information. Further, our infrastructure, networks and systems are interconnected to external networks and neighboring critical infrastructure systems. Security breaches could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information. Cyber or physical attacks, terrorist acts, or disruptive activities could harm our business by limiting our ability to generate, purchase or transmit power and by delaying the development and construction of new facilities and capital improvements to existing facilities.

In addition, our information systems and those of our third-party vendors contain confidential information, including information about customers and employees. 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.

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.

Our electric and natural gas transmission and distribution operations involve numerous activities that may result in accidents, wildfires, 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. Fires alleged to have been caused by our system could also expose us to significant damage claims on theories such as strict liability, negligence, gross negligence, trespass, inverse condemnation, and others. The risk of wildfires 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. 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 damages resulting from these risks potentially is greater. In accordance with customary industry practice, 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.

Our owned and jointly owned electric generating facilities are subject to risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, increased power purchase costs and the inability to recover our investment.

Operation of electric generating facilities involves risks, which can adversely affect energy output and efficiency levels. Operational risks include facility shutdowns due to breakdown or failure of equipment or processes, 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. In early July 2013, following the return to service from a scheduled maintenance outage, Colstrip Unit 4 tripped off-line and incurred damage to its stator and rotor. Colstrip Unit 4 returned to service in early 2014. As discussed above, we were not able to fully recover our costs for the purchase of replacement power while Colstrip Unit 4 was out of service.

Our investment in generating facilities is a long-lived asset. An early retirement of a unit before the end of the current estimated useful life or change in classification as held for use could have a material adverse impact on our results of operations. The timing of a change in estimated useful life may be dependent upon events out of our control. The costs associated with a retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs and environmental remediation costs, could be material and we have no assurance of recovery of these costs from customers.

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 these 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. However, 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 less energy available to transmit 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 life on our investment in Colstrip Unit 4 is through 2042. 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.

Colstrip Units 3 and 4 are supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019. These contracts are necessary for the long-term operation of the facility. Negotiation of a new coal supply contract anticipates environmental reviews and permitting, and we cannot predict when or if those permits will be granted. If a new coal supply contract is not in place, we could continue under the current arrangement for several years if the mining company agrees, however the extraction costs would increase.

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. 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.

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, including through the commercial paper markets. Higher interest rates on short-term borrowings with variable interest rates or on incremental commercial paper issuances could also have an adverse effect on our results of operations.

Our plans for future expansion through the acquisition of assets including natural gas reserves, capital improvements to current assets, generation investments, and transmission grid expansion involve substantial risks.

Acquisitions include a number of risks, including but not limited to, regulatory approval, 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 post-retirement 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 our 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. The annual minimum energy requirement is achievable under normal QF operations, including normal periods of planned and forced outages. However, to the extent the supplied QF 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 QF shortfall is the wholesale market, which would subject us to commodity price risk if the cost of replacement power is higher than contracted QF rates.

In addition, we are subject to price escalation risk with one of our largest QF contracts due to variable contract terms. In estimating our QF liability, we have 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 18 - 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 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 9, 2018, there were approximately 1,020 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 2017. Quarterly dividends were declared and paid on our common stock during 2017 and 2016 as set forth in the table below.

QUARTERLY COMMON STOCK PRICE RANGES AND DIVIDENDS

	Prices		
	High	Low	Cash Dividends Paid
2017-			
Fourth Quarter	$64.47	$56.44	$0.525
Third Quarter	61.80	56.87	0.525
Second Quarter	63.86	58.16	0.525
First Quarter	59.41	55.65	0.525
2016-			
Fourth Quarter	$59.13	$53.85	$0.50
Third Quarter	63.75	56.18	0.50
Second Quarter	63.30	55.34	0.50
First Quarter	62.22	52.16	0.50

On February 9, 2018, the last reported sale price on the NYSE for our common stock was $52.13.

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,				
	2017	**2016**	**2015**	**2014**	**2013**
Financial Results (in thousands, except per share data)					
Operating revenues	$ 1,305,652	$ 1,257,247	$ 1,214,299	$ 1,204,863	$ 1,154,519
Net income	162,703	164,172	151,209	120,686	93,983
Basic earnings per share	$3.35	$3.40	$3.20	$3.01	$2.46
Diluted earnings per share	3.34	3.39	3.17	2.99	2.46
Dividends declared per common share	2.10	2.00	1.92	1.60	1.52
Financial Position					
Total assets	$ 5,420,917	$ 5,499,321	$ 5,264,695	$ 4,960,902	$ 3,701,645
Total debt, including capital leases and short-term borrowings	2,137,318	2,120,474	2,026,219	1,946,790	1,313,989
Ratio of earnings to fixed charges	2.8	2.6	2.9	2.3	2.5

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 19 - 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 718,300 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 2017, 2016 and 2015. Following is a brief overview of significant developments for 2017, and a discussion of our strategy.

SIGNIFICANT DEVELOPMENTS IN 2017

- Operating income increased approximately $15.5 million due to an improvement in gross margin driven by favorable weather, and to a lesser extent, by customer growth, offset in part by an increase in property and other taxes.
  - Favorable operating income was offset by the inclusion in our 2016 results of a $17.0 million tax benefit as part of a tax accounting change related to costs to repair generation property, resulting in a $1.5 million decrease in net income.
- Successfully accessed the capital markets:
  - Received proceeds of approximately $53.7 million after commissions and other fees from the sale of 888,938 common shares under our Equity Distribution Agreement; and
  - Refinanced $250 million of Montana First Mortgage Bonds, reducing the fixed interest rate from 6.34% to 4.03% and extending the maturity from 2019 to 2047.

HOW WE PERFORMED AGAINST OUR 2016 RESULTS

	Year-over-Year Change		
Gross Margin by Segment[(1)]			
Electric	$24.3M	↑	3.6 %
Natural Gas	$14.8M	↑	8.3 %
Operating Income	$15.5M	↑	6.3 %
Net Income	$(1.5)M	↓	(0.9)%
EPS (Basic)	$(0.05)	↓	(1.5)%

(1) Non-GAAP financial measure. See "non-GAAP Financial Measure" under Results of Operations below.

SIGNIFICANT TRENDS AND REGULATION

Tax Cuts and Jobs Act

On December 22, 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. We revalued our net deferred tax liability as of December 31, 2017 based on the reduction in the overall future tax impact expected to be realized at the lower tax rate. This resulted in a reduction in our net deferred tax liability of approximately $321 million, which was offset in regulatory assets and liabilities.

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 revaluation of deferred income taxes reflects our estimate of the impact of the Tax Cuts and Jobs Act. We will continue to evaluate subsequent regulations and interpretations and assumptions made, which could materially change our estimate.

We expect to provide a customer benefit as a result of the Tax Cuts and Jobs Act in each of our jurisdictions. The MPSC and SDPUC initiated dockets regarding the impact and we expect to submit filings in Montana and South Dakota during the first quarter of 2018 with a proposal to address the effects of the lower statutory rate. As the net impact of the lower statutory rate is expected to be passed through to customers, we do not expect the Tax Cuts and Jobs Act to impact our results of operations in 2018. However, we expect a consolidated reduction in our cash flows from operations ranging from $15 million to $20 million in 2018, as a result of the reduction in revenues from customers while we are not a cash taxpayer. We currently estimate that our effective income tax rate will range from 0% to 5% in 2018.

Montana QF Tariff Filing

Under the Public Utility Regulatory Policies Act (PURPA), electric utilities are required, with exceptions, to purchase energy and capacity from independent power producers that are QFs. In May 2016, we filed an application for approval of a revised tariff for standard rates for small QFs (3 MW or less). In November 2017, the MPSC issued an order revising the QF tariff to establish a maximum contract length of 15 years and substantially lowering the rate for future QF contracts. In this order, the MPSC also upheld an initial decision to apply the contract term to our future owned and contracted electric supply resources.

As a result of this order, we terminated our competitive solicitation process for 20-year resources to determine the lowest-cost / least-risk approach for addressing our intermittent capacity and reserve margin needs in Montana. We continue to evaluate the impact of this decision, as we have significant generation capacity deficits and negative reserve margins, and our 2016 resource plan identified price and reliability risks to our customers if we rely solely upon market purchases to address these capacity needs. In addition to our responsibility to meet peak demand, national reliability standards effective July 2016 require us to have even 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. We expect to file our next electric supply resource procurement plan in late 2018.

Cost Recovery Mechanisms

Montana House Bill 193 / Electric Tracker - In April 2017, the Montana legislature passed House Bill 193 (HB 193), amending the statute that provided for mandatory recovery of our prudently incurred electric supply costs effective July 1, 2017. The revised statute gives the MPSC discretion whether to approve an electric supply cost adjustment mechanism. The MPSC initiated a process to develop a replacement electric supply cost adjustment mechanism, and in response, in July 2017, we filed a proposed electric PCCAM. Intervenor testimony was filed in November 2017, and in December 2017, the MPSC issued a Notice of Additional Issues stating that the range of options proposed by the parties was not sufficient and directing parties to consider alternatives incorporating risk-sharing features of other utilities in the region.

Our July 2017 PCCAM filing is consistent with our understanding of the MPSC's advocacy for HB 193, which referenced the Montana-Dakota Utilities (MDU) adjustment mechanism used in Montana that allows for recovery of 90 percent of the increases or decreases in fuel and purchased energy costs from an established baseline. However, we cannot guarantee how the MPSC may apply the statute in establishing a revised mechanism for us. We filed rebuttal testimony in February 2018, responsive to intervenor testimony and the MPSC's December 2017 Notice of Additional Issues, addressing alternative risk-sharing mechanisms. A hearing is scheduled to begin May 31, 2018. If the MPSC approves a new mechanism, the MPSC may apply the mechanism to variable costs on a retroactive basis to the effective date of HB 193 (July 1, 2017).

FERC Filing - Dave Gates Generating Station at Mill Creek (DGGS)

In May 2016, we received an order from the FERC denying a May 2014 request for rehearing and requiring us to make refunds. The request for rehearing challenged a September 2012 FERC Administrative Law Judge's (ALJ) initial decision regarding cost allocation of DGGS between retail and wholesale customers. The 2012 decision concluded that only a portion of these costs should be allocated to FERC jurisdictional customers. We had cumulative deferred revenue of approximately $27.3 million, consistent with the ALJ's initial decision, which was refunded to wholesale and choice customers in June 2016 in accordance with the FERC order.

In June 2016, we filed a petition for review of the FERC's May 2016 order with the United States Circuit Court of Appeals for the District of Columbia Circuit (D.C. Circuit). A hearing was held on December 1, 2017. We expect a decision in this matter by the end of the second quarter of 2018.

STRATEGY

We operate a fully regulated electric and natural gas utility. We seek to deliver value to our customers by providing high reliability and customer service, an environmentally sustainable generation mix and a typical residential customer bill that is below the national average benchmark. 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 environmental considerations with more predictable long-term commodity prices. Resource planning is an important function necessary to meet our future energy and reserve margin needs. Based on our current analysis, we are considering electric supply capacity investments and expect to continue to pursue opportunities to add to our natural gas reserves portfolio.

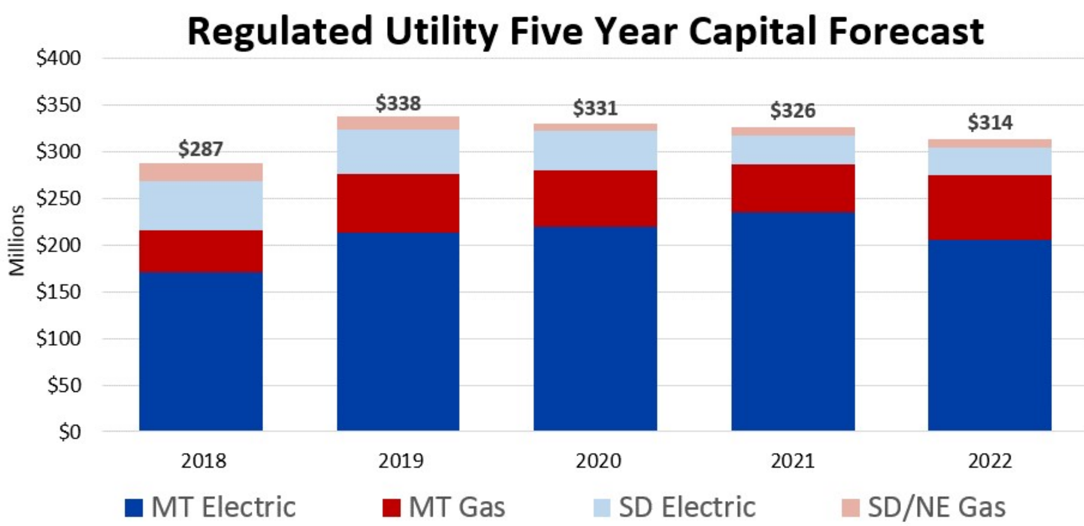
- We continually look for ways to increase our operating efficiency. Financial discipline is essential to earning our authorized return on invested capital and maintaining a strong balance sheet, stable cash flows, and quality credit ratings.

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. See the “Capital Requirements" discussion below for further detail on planned capital expenditures.

Rate cases are necessary to recover the cost of providing safe, reliable service, while contributing to earnings growth and achieving our financial objectives. We typically evaluate the need for electric and natural gas rate changes annually. We plan to file a Montana electric general rate case in 2018, based on a 2017 test year, and expect to complete the evaluation of the need for a rate case for our remaining jurisdictions during the first quarter of 2018.

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	**2018**	**2019**	**2020**	**2021**	**2022**
Electric	$ 223.1	$ 261.5	$ 262.5	$ 267.1	$ 236.0
Natural Gas	64.3	76.5	68.4	58.9	78.1
Total Capital Forecast	$ 287.4	$ 338.0	$ 330.9	$ 326.0	$ 314.1

Supply Investments

Our resource plans identify portfolio resource requirements including potential investments. 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 through the addition of regulated assets that are not subject to market forces. As of December 31, 2017, these owned reserves totaled approximately 55.9 Bcf and are estimated to provide approximately 4.5 Bcf in 2018, or about 22 percent of our expected annual retail natural gas load in Montana. We continue to pursue opportunities to secure low cost gas reserves for our customers, with a target of owning 50% of our supply. 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.

As discussed above, due to the MPSC's decision regarding maximum contract length in the QF tariff docket, we terminated our competitive solicitation process to determine the lowest-cost / least-risk approach for addressing our intermittent capacity and reserve margin needs in Montana. We expect to file an electric supply resource procurement plan in Montana in late 2018 and are evaluating our options to address our significant generation capacity deficits and negative reserve margins.

Distribution and Transmission System Investment

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 working on various solutions 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.

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. Gross Margin (Revenues less Cost of Sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of Gross Margin is intended to supplement investors' understanding of our operating performance. 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. Our Gross Margin measure may not be comparable to other companies' Gross Margin measures. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

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, 2017 Compared with Year Ended December 31, 2016

	Year Ended December 31,			
	2017	2016	Change	% Change
	(in millions)			
Operating Revenues				
Electric	$ 1,037.1	$ 1,011.6	$ 25.5	2.5%
Natural Gas	268.6	245.7	22.9	9.3
	$ 1,305.7	$ 1,257.3	$ 48.4	3.8%

	Year Ended December 31,			
	2017	2016	Change	% Change
	(in millions)			
Cost of Sales				
Electric	$ 334.0	$ 332.8	$ 1.2	0.4%
Natural Gas	76.3	68.2	8.1	11.9
	$ 410.3	$ 401.0	$ 9.3	2.3%

	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
	$ 895.4	$ 856.3	$ 39.1	4.6%

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:

		Gross Margin 2017 vs. 2016
		(in millions)
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 in Operating Expenses and Income Tax Expense		
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	**$**	**39.1**

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	$ 305.1	$ 302.9	$ 2.2	0.7%
Property and other taxes	162.6	148.1	14.5	9.8
Depreciation and depletion	166.1	159.3	6.8	4.3
	$ 633.8	$ 610.3	$ 23.5	3.9%

Consolidated operating, general and administrative expenses were $305.1 million in 2017 as compared with $302.9 million in 2016. Primary components of this change include the following:

	Operating, General, & Administrative Expenses 2017 vs. 2016
	(in millions)
Bad debt expense	$ 1.9
Operating expenses recovered in trackers	1.5
Maintenance costs	1.2
Employee benefits and compensation costs	(1.5)
Insurance reserves	(1.0)
Other	0.1
Increase in Operating, General & Administrative Expenses	**$ 2.2**

The increase in operating, general and administrative expenses of $2.2 million was 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;
- Higher operating expenses recovered through our supply trackers; 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.

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. Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and adjust our rates to recover the increase between rate cases less the amount allocated to FERC-jurisdictional customers and net of the associated income tax benefit. In January 2018, the MPSC issued an order in our 2017 filing reducing our recovery of these taxes by approximately $1.7 million by applying an alternate allocation methodology. This results in a lower allocation to our Montana electric retail customers and a higher property tax allocation to FERC transmission customers (we do not have a property tax tracker for FERC jurisdictional purposes).

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 $261.4 million, as compared with $245.9 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. We expect interest expense to decrease by approximately $2 million in 2018 as a result of these refinancing transactions offset by rising interest rates.

Consolidated other income in 2017 was $6.9 million as compared with $5.5 million in 2016. This increase was primarily due to 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.

Year Ended December 31, 2016 Compared with Year Ended December 31, 2015

	Year Ended December 31,			
	2016	2015	Change	% Change
	(in millions)			
Operating Revenues				
Electric	$ 1,011.6	$ 944.4	$ 67.2	7.1%
Natural Gas	245.7	269.9	(24.2)	(9.0)
	$ 1,257.3	$ 1,214.3	$ 43.0	3.5%

	Year Ended December 31,			
	2016	2015	Change	% Change
	(in millions)			
Cost of Sales				
Electric	$ 332.8	$ 281.3	$ 51.5	18.3%
Natural Gas	68.2	91.6	(23.4)	(25.5)
	$ 401.0	$ 372.9	$ 28.1	7.5%

	Year Ended December 31,			
	2016	2015	Change	% Change
	(in millions)			
Gross Margin				
Electric	$ 678.8	$ 663.1	$ 15.7	2.4%
Natural Gas	177.5	178.3	(0.8)	(0.4)
	$ 856.3	$ 841.4	$ 14.9	1.8%

Consolidated gross margin in 2016 was $856.3 million, an increase of $14.9 million, or 1.8%, from gross margin in 2015. Factors that impacted gross margin included:

	Gross Margin 2016 vs. 2015
	(in millions)
Gross Margin Items Impacting Net Income	
South Dakota electric rate increase	$ 33.5
Lost revenue adjustment mechanism	7.7
Electric QF adjustment	6.1
Natural gas retail volumes	0.2
MPSC disallowance	(9.5)
Electric transmission	(3.6)
Electric retail volumes	(2.0)
Hydro generation rates	(1.5)
Natural gas production rates	(1.2)
Other	(1.5)
Consolidated Gross Margin Impacting Net Income	**28.2**
Gross Margin Items Offset in Operating Expenses and Income Tax Expense	
Hydro operations - Kerr conveyance	(16.5)
Production tax credits flowed-through trackers	(8.2)
Natural gas production gathering fees	(1.1)
Property taxes recovered in trackers	12.5
Change in Items Offset Within Net Income	**(13.3)**
Increase in Consolidated Gross Margin	**$ 14.9**

Consolidated gross margin for items impacting net income increased $28.2 million primarily due to the following:

- An increase in South Dakota electric rates;
- The recognition of $14.2 million of deferred revenue as a result of a MPSC final order in our tracker filings, offset in part by the elimination of the lost revenue adjustment mechanism decreasing the recovery of our fixed costs by approximately $6.5 million;
- The inclusion in our 2015 results of an increase in supply costs due to the adjustment of the QF liability based on a review of contract assumptions; and
- An increase in our Montana jurisdiction residential and commercial natural gas volumes due to colder late summer and winter weather, and customer growth, offset by warmer winter weather in our South Dakota jurisdiction.

These increases were partly offset by:

- An MPSC disallowance of previously incurred replacement power and modeling / planning costs;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing;
- A decrease in electric retail volumes due primarily to colder late summer weather in our Montana jurisdiction, along with lower industrial volumes of a large Montana customer, partly offset by warmer spring and summer weather in our South Dakota jurisdiction and customer growth;
- A reduction in hydro generation rates due to the MPSC order in the hydro compliance filing; and
- A decrease in natural gas production margin due to an $0.8 million decrease in overhead fees and a $0.4 million decrease in interim rates based on actual costs.

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

- A decrease in revenues from the conveyance of the Kerr facility to the Confederated Salish and Kootenai Tribes (CSKT) in September 2015 (offset by reduced operating expenses);
- A decrease in revenues for production tax credits primarily associated with the Beethoven wind generation project, which is a reduction in our customers rates (offset by reduced income tax expense);
- A decrease in natural gas production gathering fees (offset by reduced operating expenses); and
- An increase in revenues for property taxes included in trackers (offset by increased property tax expense).

	Year Ended December 31,			
	2016	2015	Change	% Change
	(in millions)			
Operating Expenses (excluding cost of sales)				
Operating, general and administrative	$ 302.9	$ 297.5	$ 5.4	1.8%
Property and other taxes	148.1	133.4	14.7	11.0
Depreciation and depletion	159.3	144.7	14.6	10.1
	$ 610.3	$ 575.6	$ 34.7	6.0%

Consolidated operating, general and administrative expenses were $302.9 million in 2016 as compared with $297.5 million in 2015. Primary components of this change include the following:

		Operating, General, & Administrative Expenses 2016 vs. 2015
		(in millions)
Insurance recovery, net	$	20.8
Employee benefit and compensation costs		2.7
Plant operator costs		2.2
Non-employee directors deferred compensation		1.5
Insurance reserves		0.9
Hydro operations - Kerr conveyance		(15.2)
DSIP expenses		(4.0)
Natural gas production gathering expense		(1.1)
Bad debt expense		(1.0)
Other		(1.4)
Increase in Operating, General & Administrative Expenses	$	5.4

The increase in operating, general and administrative expenses of $5.4 million was primarily due to the following:

- The inclusion in our second quarter 2015 results of an insurance recovery, primarily associated with electric generation related environmental remediation costs incurred in prior periods;
- An increase in employee related benefits costs due to higher compensation and pension costs;
- Higher plant operator costs primarily due to the Beethoven acquisition in September 2015;
- The change in value of non-employee directors deferred compensation due to changes in our stock price (offset by changes in other income with no impact on net income); and
- An increase in insurance reserves primarily due to the Billings, Montana refinery outage discussed in Note 18 to the Consolidated Financial Statements.

These increases were offset in part by:

- A decrease in hydro operations costs in the current period as a result of the conveyance of Kerr to the CSKT in September 2015 (offset by reduced revenue discussed above);
- Lower DSIP related expenses;
- A decrease in natural gas production gathering expense (offset by lower gathering fees discussed above); and
- Lower bad debt expense, due to improved collection of receivables from customers.

In addition, cost control measures implemented in 2016 are included in the Other line item above.

Property and other taxes were $148.1 million in 2016 as compared with $133.4 million in 2015. This increase was primarily due to plant additions and higher estimated property valuations in Montana, offset in part by a $1.3 million decrease from the conveyance of Kerr to the CSKT in September 2015.

Depreciation and depletion expense was $159.3 million in 2016 as compared with $144.7 million in 2015. This increase was primarily due to plant additions, including approximately $4.3 million of incremental depreciation associated with the September 2015 Beethoven wind project acquisition.

Consolidated operating income in 2016 was $245.9 million, as compared with $265.8 million in 2015. This decrease was primarily due to the $20.8 million insurance recovery in 2015.

Consolidated interest expense in 2016 was $95.0 million, as compared with $92.2 million, in 2015. This increase was primarily due to $2.9 million of interest associated with the MPSC disallowance as discussed above, lower capitalization of AFUDC, and increased debt outstanding, partly offset by the debt refinancing transactions.

Consolidated other income in 2016 was $5.5 million as compared with $7.6 million in 2015. This decrease was primarily due to lower capitalization of AFUDC, partly offset by a $1.5 million increase in the value of deferred shares held in trust for non-employee directors deferred compensation (which, as discussed above, is offset by a corresponding increase to operating, general and administrative expenses).

Consolidated income tax benefit in 2016 was $7.6 million as compared with income tax expense of $30.0 million in 2015. Our effective tax rate for the twelve months ended December 31, 2016 was (4.9)% as compared with 16.6% for the same period of 2015. During the third quarter of 2016, we filed a tax accounting method change with the Internal Revenue Service (IRS) related to costs to repair generation property, as discussed above. This resulted in an income tax benefit of approximately $17.0 million during the twelve months ended December 31, 2016, of which approximately $12.5 million related to 2015 and prior tax years and is reflected in the flow-through repairs deductions line below. In addition, we adopted the provisions of a new accounting standard related to share-based payments, during the fourth quarter of 2016. The excess tax benefit of share awards that vested in 2016 was treated as a discrete item.

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

	Year Ended December 31,			
	2016		2015	
Income Before Income Taxes	$ 156.5		$ 181.2	
Income tax calculated at 35% Federal statutory rate	54.8	35.0 %	63.4	35.0%
Permanent or flow through adjustments:				
State income, net of federal provisions	(3.7)	(2.4)	0.3	0.1
Flow through repairs deductions	(41.1)	(26.3)	(24.1)	(13.3)
Production tax credits	(10.9)	(7.0)	(5.7)	(3.2)
Plant and depreciation of flow through items	(4.6)	(2.9)	(2.9)	(1.6)
Share based compensation	(1.6)	(1.1)	—	—
Prior year permanent return to accrual adjustments	(0.1)	(0.1)	0.2	0.1
Other, net	(0.4)	(0.1)	(1.2)	(0.5)
	(62.4)	(39.9)	(33.4)	(18.4)
Income Tax (Benefit) Expense	$ (7.6)	(4.9)%	$ 30.0	16.6%

Consolidated net income in 2016 was $164.2 million as compared with $151.2 million in 2015. This increase was primarily due to the tax benefit related to costs to repair generation property discussed above along with improved gross margin driven by an increase in South Dakota electric rates, partly offset by the inclusion in our 2015 results of a $20.8 million insurance recovery and higher property tax and depreciation expense in 2016.

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.
- Ancillary Services: FERC jurisdictional services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services include regulation services, reserves and voltage support.
- Wholesale and other: Our South Dakota service territory is a market participant in the SPP, where we buy and sell wholesale energy and reserves through the operation of a single, consolidated balancing authority. This line also includes miscellaneous electric revenues.

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	58.1	51.1	7.0	13.7
Ancillary services	1.6	1.6	—	—
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	**$ 703.1**	**$ 678.8**	**$ 24.3**	**3.6%**

	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:

	Gross Margin 2017 vs. 2016	
	(in millions)	
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
Consolidated Gross Margin Impacting Net Income		**17.9**
Gross Margin Items Offset in Operating Expenses and Income Tax Expense		
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 Consolidated Gross Margin	**$**	**24.3**

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.

In addition, 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, 2016 Compared with Year Ended December 31, 2015

	Results			
	2016	2015	Change	% Change
	(in millions)			
Retail revenue	$ 840.7	$ 819.8	$ 20.9	2.5 %
Regulatory amortization	20.9	39.4	(18.5)	(47.0)
Total retail revenues	861.6	859.2	2.4	0.3
Transmission	51.1	54.7	(3.6)	(6.6)
Ancillary services	1.6	1.5	0.1	6.7
Wholesale and other	97.3	29.0	68.3	235.5
Total Revenues	**1,011.6**	**944.4**	**67.2**	**7.1**
Total Cost of Sales	**332.8**	**281.3**	**51.5**	**18.3%**
Gross Margin	**$ 678.8**	**$ 663.1**	**$ 15.7**	**2.4%**

	Revenues		Megawatt Hours (MWH)		Avg. Customer Counts	
	2016	2015	2016	2015	2016	2015
	(in thousands)					
Montana	$ 280,379	$ 275,971	2,372	2,359	291,348	287,387
South Dakota	57,369	49,469	548	551	50,016	49,807
Residential	**337,748**	**325,440**	**2,920**	**2,910**	**341,364**	**337,194**
Montana	343,982	344,743	3,177	3,207	65,568	64,711
South Dakota	87,199	75,442	985	974	12,591	12,473
Commercial	**431,181**	**420,185**	**4,162**	**4,181**	**78,159**	**77,184**
Industrial	40,577	43,838	2,204	2,260	74	75
Other	31,162	30,348	188	187	6,143	6,119
Total Retail Electric	**$ 840,668**	**$ 819,811**	**$ 9,474**	**$ 9,538**	**$ 425,740**	**$ 420,572**

	Cooling Degree Days			2016 as compared with:	
	2016	2015	Historic Average	2015	Historic Average
Montana	367	440	433	17% colder	15% colder
South Dakota	895	792	733	13% warmer	22% warmer

	Heating Degree Days			2016 as compared with:	
	2016	2015	Historic Average	2015	Historic Average
Montana	7,011	6,914	7,498	1% colder	6% warmer
South Dakota	6,593	6,924	7,674	5% warmer	14% warmer

The following summarizes the components of the changes in electric margin for the years ended December 31, 2016 and 2015:

	Gross Margin 2016 vs. 2015 (in millions)
Gross Margin Items Impacting Net Income	
South Dakota rate increase	$ 33.5
Lost revenue adjustment mechanism	7.1
QF adjustment	6.1
MPSC disallowance	(9.5)
Transmission	(3.6)
Retail volumes	(2.0)
Hydro generation rates	(1.5)
Consolidated Gross Margin Impacting Net Income	**30.1**
Gross Margin Items Offset in Operating Expenses and Income Tax Expense	
Hydro operations - Kerr conveyance	(16.5)
Production tax credits flowed-through trackers	(8.2)
Property taxes recovered in trackers	10.3
Change in Items Offset Within Net Income	**(14.4)**
Increase in Consolidated Gross Margin	**$ 15.7**

Gross margin for items impacting net income increased $30.1 million including the following:

- An increase in South Dakota electric rates;
- The recognition of $13.4 million of deferred revenue as a result of a MPSC final order in our tracker filings, offset in part by the elimination of the lost revenue adjustment mechanism decreasing the recovery of our fixed costs; and
- The inclusion in our 2015 results of an increase in supply costs due to the adjustment of the QF liability based on a review of contract assumptions.

These increases were partly offset by:

- The MPSC disallowance of previously incurred costs as discussed above;
- Lower demand to transmit energy across our transmission lines due to market conditions and pricing;
- A decrease in electric retail volumes due primarily to colder late summer weather in our Montana jurisdiction, along with lower industrial volumes of a large Montana customer, partly offset by warmer spring and summer weather in our South Dakota jurisdiction and customer growth; and
- A reduction in hydro generation rates due to the MPSC order in the hydro compliance filing as discussed above;

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

- A decrease in revenues from the conveyance of the Kerr facility to the CSKT in September 2015 (offset by reduced operating expenses);
- A decrease in revenues for production tax credits primarily associated with the Beethoven wind generation project, which is a reduction in our customers rates (offset by reduced income tax expense); and
- An increase in revenues for property taxes included in trackers (offset by increased property tax expense).

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

NATURAL GAS 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, 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	**$ 192.3**	**$ 177.5**	**$ 14.8**	**8.3%**

	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:

		Gross Margin 2017 vs. 2016
		(in millions)
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 in Operating Expenses		
Property taxes recovered in trackers		1.8
Change in Items Offset Within Net Income		**1.8**
Increase in Consolidated Gross Margin	**$**	**14.8**

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 a 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.

In addition, average natural gas supply prices increased in 2017 as compared with 2016, resulting in higher retail revenues and cost of sales, with no impact to 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, 2016 Compared with Year Ended December 31, 2015

	Results			
	2016	2015	Change	% Change
	(in millions)			
Retail revenue	$ 201.8	$ 223.5	$ (21.7)	(9.7)%
Regulatory amortization	4.8	5.9	(1.1)	(18.6)
Total retail revenues	206.6	229.4	(22.8)	(9.9)
Wholesale and other	39.1	40.5	(1.4)	(3.5)
Total Revenues	**245.7**	**269.9**	**(24.2)**	**(9.0)**
Total Cost of Sales	**68.2**	**91.6**	**(23.4)**	**(25.5)**
Gross Margin	**$ 177.5**	**$ 178.3**	**$ (0.8)**	**(0.4)%**

	Revenues		Dekatherms (Dkt)		Customer Counts	
	2016	2015	2016	2015	2016	2015
	(in thousands)					
Montana	$ 93,034	$ 98,030	12,178	11,809	168,220	166,070
South Dakota	20,399	24,429	2,533	2,673	39,207	38,858
Nebraska	17,043	20,948	2,179	2,340	37,129	36,947
Residential	**130,476**	**143,407**	**16,890**	**16,822**	**244,556**	**241,875**
Montana	46,515	49,374	6,343	6,203	23,223	22,943
South Dakota	14,051	16,969	2,665	2,700	6,456	6,295
Nebraska	8,858	11,700	1,689	1,810	4,725	4,650
Commercial	**69,424**	**78,043**	**10,697**	**10,713**	**34,404**	**33,888**
Industrial	1,031	1,168	147	152	259	263
Other	888	854	137	123	157	153
Total Retail Gas	**$ 201,819**	**$ 223,472**	**27,871**	**27,810**	**279,376**	**276,179**

	Heating Degree Days			2016 as compared with:	
	2016	2015	Historic Average	2015	Historic Average
Montana	7,300	7,172	7,837	2% colder	7% warmer
South Dakota	6,593	6,924	7,674	5% warmer	14% warmer
Nebraska	5,322	5,663	6,333	6% warmer	16% warmer

The following summarizes the components of the changes in natural gas margin for the years ended December 31, 2016 and 2015:

	Gross Margin 2016 vs. 2015
	(in millions)
Gross Margin Items Impacting Net Income	
Production	$ (1.2)
Lost revenue adjustment mechanism	0.6
Retail volumes	0.2
Other	(1.5)
Change in Gross Margin Impacting Net Income	**(1.9)**
Gross Margin Items Offset in Operating Expenses	
Property taxes recovered in trackers	2.2
Production gathering fees	(1.1)
Change in Items Offset Within Net Income	**1.1**
Decrease in Consolidated Gross Margin	**$ (0.8)**

Gross margin for items impacting net income decreased $1.9 million including the following:

- A decrease in production margin due to an $0.8 million decrease in overhead fees and a $0.4 million decrease in interim rates based on actual costs; partly offset by
- The recognition of deferred revenue as a result of a MPSC final order in our tracker filings, which was offset in part by the elimination of the lost revenue adjustment mechanism decreasing the recovery of our fixed costs; and
- An increase in our Montana jurisdiction residential and commercial volumes due to colder late summer and winter weather, and customer growth, partly offset by warmer winter weather in our South Dakota jurisdiction.

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

- An increase in revenues for property taxes included in trackers (offset by increased property tax expense); and
- A decrease in production gathering fees (offset by reduced operating expenses).

In addition, average natural gas supply prices decreased in 2016 as compared with 2015, resulting in lower retail revenues and cost of sales, with no impact to gross margin. Our wholesale and other revenues are largely gross margin neutral as they are offset by changes in cost of sales.

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.

Short-term liquidity is provided by internal cash flows, the sale of commercial paper and use of our unsecured revolving credit facility. We utilize our short-term borrowings and / or revolver availability 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, 2017, our total net liquidity was approximately $88.9 million, including $8.5 million of cash and $80.4 million of revolving credit facility availability. As of December 31, 2017, there were no letters of credit outstanding.

We issue debt securities to refinance retiring maturities, reduce short-term 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 pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. During 2017, we received net proceeds of approximately $53.7 million from the sale of 888,938 shares of our common stock after commissions and other fees. During the three months ended December 31, 2017, we issued 805,169 shares for net proceeds of $48.9 million after commissions and other fees. We expect to issue the remaining $46 million of shares under the Equity Distribution Agreement during 2018.

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.

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.

We closely monitor the financial institutions associated with our credit facility. A total of eight banks participate in our revolving credit facility, with no one bank providing more than 16% of the total availability. As of December 31, 2017, no bank has advised us of its intent to withdraw from the revolving credit facility or to not honor its obligations. Our revolving credit facility requires us to maintain a debt to capitalization ratio at or below 65%. At December 31, 2017, we were in compliance with this ratio. The revolving credit facility also contains default and related acceleration provisions related to default on other debt. The following table presents additional information about short term borrowings during the year ended December 31, 2017 (in millions):

Amount outstanding at year end	$	319.6
Daily average amount outstanding	$	251.7
Maximum amount outstanding	$	332.5
Minimum amount outstanding	$	193.8

As of February 9, 2018, our availability under our revolving credit facility was approximately $136.0 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 impact our trade credit availability. 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 9, 2018, 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)	A2	Baa1	Prime-2	Negative
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 an adverse outcome in either our Montana electric supply tracker docket or upcoming electric general rate case would likely result in a one-notch downgrade.
(2) In March 2017, Moody's downgraded our senior secured rating to A2 from A1, and our unsecured credit rating to Baa1 from A3, while maintaining a negative outlook. Moody's cited weak financial metrics and a heightened degree of regulatory uncertainty in Montana as reasons for the downgrade. Moody's maintains a negative outlook, citing a more contentious regulatory relationship in Montana, our primary regulatory jurisdiction, resulting in unpredictable regulatory outcomes. We expect Moody's to take action on the negative outlook during the first half of 2018.

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 "Strategy" 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, 2017. See additional discussion in Note 18 – Commitments and Contingencies to the Consolidated Financial Statements.

	Total	2018	2019	2020	2021	2022	Thereafter
				(in thousands)			
Long-term debt (1)	$ 1,806,637	$ —	$ —	$ —	$ —	$ —	$ 1,806,637
Capital leases	24,346	2,133	2,298	2,476	2,668	2,875	11,896
Short-term borrowings	319,556	319,556	—	—	—	—	—
Estimated pension and other postretirement obligations (2)	61,049	12,560	12,322	12,196	12,053	11,918	N/A
Qualifying facilities (3) liability	807,421	76,703	78,836	80,984	82,941	84,948	403,009
Supply and capacity contracts (4)	2,066,203	190,554	179,043	134,818	113,877	115,983	1,331,928
Contractual interest payments on debt (5)	1,571,573	76,621	76,621	76,621	76,279	71,632	1,193,799
Environmental remediation obligations (2)	4,600	1,250	1,100	1,050	600	600	N/A
Total Commitments (6)	$ 6,661,385	$ 679,377	$ 350,220	$ 308,145	$ 288,418	$ 287,956	$ 4,747,269

(1) Represents cash payments for long-term debt and excludes $13.2 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 $61 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these QFs is approximately $807.4 million. A portion of the costs incurred to purchase this energy is recoverable through rates authorized by the MPSC, totaling approximately $625.6 million.
(4) We have entered into various purchase commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 26 years.
(5) For our variable rate short-term borrowings outstanding, we have assumed an average interest rate of 1.75% through maturity.
(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 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.

As of December 31, 2017, we are under collected on our natural gas and electric trackers by approximately $13.2 million, as compared with $11.7 million as of December 31, 2016, and $29.4 million as of December 31, 2015.

Cash Flows

The following table summarizes our consolidated cash flows for 2017, 2016 and 2015.

	Year Ended December 31,		
	2017	2016	2015
Operating Activities			
Net income	$ 162.7	$ 164.2	$ 151.2
Non-cash adjustments to net income	182.7	155.4	177.2
Changes in working capital	(14.4)	(25.1)	10.1
Other noncurrent assets and liabilities	(7.4)	(5.5)	1.3
	323.6	**289.0**	**339.8**
Investing Activities			
Property, plant and equipment additions	(276.4)	(287.9)	(283.7)
Acquisitions	—	—	(146.7)
Change in restricted cash	—	—	16.1
Proceeds from sale of assets	0.4	1.4	30.2
	(276.0)	**(286.5)**	**(384.1)**
Financing Activities			
Proceeds from issuance of common stock, net	53.7	—	56.7
Issuances of long-term debt, net	—	24.5	120.0
Issuances (repayments) of short-term borrowings, net	18.7	70.9	(38.0)
Dividends on common stock	(101.3)	(95.8)	(90.1)
Financing costs	(16.4)	(8.4)	(12.1)
Other	1.1	(0.6)	(0.6)
	(44.2)	**(9.4)**	**35.9**
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 3.4**	**$ (6.9)**	**$ (8.4)**
Cash and Cash Equivalents, beginning of period	$ 5.1	$ 12.0	$ 20.4
Cash and Cash Equivalents, end of period	**$ 8.5**	**$ 5.1**	**$ 12.0**

Cash Flows Provided By Operating Activities

As of December 31, 2017, our cash and cash equivalents were $8.5 million as compared with $5.1 million at December 31, 2016. Cash provided by operating activities totaled $323.6 million for the year ended December 31, 2017 as compared with $289.0 million during 2016. This increase in operating cash flows is primarily due to refunds 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, to customers during 2016, and to higher net income after non-cash adjustments during 2017.

Our 2016 operating cash flows decreased by approximately $50.8 million as compared with 2015. This decrease in operating cash flows is primarily due to refunds associated with the DGGS FERC ruling and interim rates in our South Dakota electric rate case described above during 2016, and lower collections from customers in 2016 as compared to 2015, which are reflected in the changes in working capital. In addition, net income after non-cash adjustments was lower in 2016.

Cash Flows Used In Investing Activities

Cash used in investing activities totaled $276.0 million during the year ended December 31, 2017, as compared with $286.5 million during 2016, and $384.1 million in 2015. 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. During 2015, we purchased the 80 MW Beethoven wind project in South Dakota for approximately $143 million.

Cash Flows (Used in) Provided By Financing Activities

Cash used in financing activities totaled $44.2 million during 2017 as compared to $9.4 million during 2016 and cash provided by financing activities of $35.9 million during 2015. 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. During 2015, net cash provided by financing activities includes net proceeds from the issuance of debt of $120.0 million and common stock issuances of $56.7 million, partially offset by net repayments of commercial paper of $38.0 million, the payment of dividends of $90.1 million and the payment of financing costs of $12.1 million.

Financing Transactions - In September 2017, we entered into an Equity Distribution Agreement pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. During 2017, we received net proceeds of approximately $53.7 million from the sale of 888,938 shares of our common stock after commissions and other fees.

In addition, 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.

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 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 4 – 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 14 - 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, 2017, our discount rate on the NorthWestern Corporation pension plan is 3.50% and on the NorthWestern Energy pension plan is 3.60%.

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 4.47% and 4.97% on the NorthWestern Corporation and NorthWestern Energy pension plan, respectively, for 2018.

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 %	$ (1,996)	$ (22)
	(0.25)%	2,132	24
Rate of return on plan assets	0.25 %	(1,275)	N/A
	(0.25)%	1,275	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, 2017, we have approximately $421 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 $57.5 million as of December 31, 2017. 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.

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 facility. The revolving credit facility bears interest at the lower of prime or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.88% to 1.75%. To more cost effectively meet short-term cash requirements, we issue commercial paper supported by our revolving credit facility. Since commercial paper terms are short-term, we are subject to interest rate risk. As of December 31, 2017, we had approximately $319.6 million of commercial paper outstanding and no borrowings on our revolving credit facility. A 1% increase in interest rates would increase our annual interest expense by approximately $3.2 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 substantially mitigated because these commodity costs are included in our cost tracking mechanisms and are recoverable from customers subject to prudence reviews by applicable state regulatory commissions.

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-45 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, 2017, 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, 2017. 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, 2017, 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 2018 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 2018 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 2018 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 2018 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 2018 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) †	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 11, 2015, Commission File No. 1-10499).
10.1(j) †	NorthWestern Energy 2016 Annual Incentive Plan (incorporated by reference to Exhibit 99.1 of NorthWestern Corporation's Current Report on Form 8-K, dated February 16, 2016, Commission File No. 1-10499).
10.1(k) †	Form of NorthWestern Corporation Performance Unit Award Agreement (incorporated by reference to Exhibit 99.2 of NorthWestern Corporation's Current Report on Form 8-K, dated February 16, 2016, Commission File No. 1-10499).
10.1(l) †	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(m) †	NorthWestern Energy 2017 Annual Incentive Plan (incorporated by reference to Exhibit 99.01 of NorthWestern Corporation's Current Report on Form 8-K, dated December 13, 2016, 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 13, 2016, Commission File No. 1-10499).
10.1(o) †	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).
10.2(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).
12.1*	Statement Regarding Computation of Earnings to Fixed Charges.
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 13, 2018	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/ E. LINN DRAPER JR. E. Linn Draper Jr.	Chairman of the Board	February 13, 2018
/s/ ROBERT C. ROWE Robert C. Rowe	President, Chief Executive Officer and Director (Principal Executive Officer)	February 13, 2018
/s/ BRIAN B. BIRD Brian B. Bird	Vice President and Chief Financial Officer (Principal Financial Officer)	February 13, 2018
/s/ CRYSTAL D. LAIL Crystal D. Lail	Vice President and Controller (Principal Accounting Officer)	February 13, 2018
/s/ STEPHEN P. ADIK Stephen P. Adik	Director	February 13, 2018
/s/ ANTHONY T. CLARK Anthony T. Clark	Director	February 13, 2018
/s/ DANA J. DYKHOUSE Dana J. Dykhouse	Director	February 13, 2018
/s/ BRITT E. IDE Britt E. Ide	Director	February 13, 2018
/s/ JAN R. HORSFALL Jan R. Horsfall	Director	February 13, 2018
Julia L. Johnson	Director	
Linda G. Sullivan	Director	

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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, 2017 and 2016, 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, 2017, 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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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, 2017, 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 12, 2018, 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 12, 2018
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, 2017, 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, 2017, 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, 2017, of the Company and our report dated February 12, 2018, expressed an unqualified opinion of 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 12, 2018

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)

	Year Ended December 31,		
	2017	2016	2015
Revenues			
Electric	$ 1,037,053	$ 1,011,595	$ 944,428
Gas	268,599	245,652	269,871
Total Revenues	1,305,652	1,257,247	1,214,299
Operating Expenses			
Cost of sales	410,349	400,973	372,864
Operating, general and administrative	305,137	302,893	297,475
Property and other taxes	162,614	148,098	133,442
Depreciation and depletion	166,137	159,336	144,702
Total Operating Expenses	1,044,237	1,011,300	948,483
Operating Income	261,415	245,947	265,816
Interest Expense, net	(92,263)	(94,970)	(92,153)
Other Income, net	6,919	5,548	7,583
Income Before Income Taxes	176,071	156,525	181,246
Income Tax (Expense) Benefit	(13,368)	7,647	(30,037)
Net Income	$ 162,703	$ 164,172	$ 151,209
Average Common Shares Outstanding	48,558	48,299	47,298
Basic Earnings per Average Common Share	$ 3.35	$ 3.40	$ 3.20
Diluted Earnings per Average Common Share	$ 3.34	$ 3.39	$ 3.17

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
Net Income	$ 162,703	$ 164,172	$ 151,209
Other comprehensive income (loss), net of tax:			
Reclassification of net losses (gains) on derivative instruments	371	(1,338)	(698)
Postretirement medical liability adjustment	773	195	310
Foreign currency translation	(202)	25	558
Total Other Comprehensive Income (Loss)	942	(1,118)	170
Comprehensive Income	$ 163,645	$ 163,054	$ 151,379

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

	Year Ended December 31, 2017	2016
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 8,473	$ 5,079
Restricted cash	3,556	4,426
Accounts receivable, net	182,282	159,556
Inventories	52,432	49,206
Regulatory assets	37,669	50,041
Other	11,947	11,887
Total current assets	**296,359**	**280,195**
Property, plant, and equipment, net	4,358,265	4,214,892
Goodwill	357,586	357,586
Regulatory assets	354,316	602,943
Other noncurrent assets	54,391	43,705
Total Assets	**$ 5,420,917**	**$ 5,499,321**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Current maturities of capital leases	$ 2,133	$ 1,979
Short-term borrowings	319,556	300,811
Accounts payable	85,160	79,311
Accrued expenses	210,047	205,370
Regulatory liabilities	15,342	26,361
Total current liabilities	**632,238**	**613,832**
Long-term capital leases	22,213	24,346
Long-term debt	1,793,416	1,793,338
Deferred income taxes	340,729	575,582
Noncurrent regulatory liabilities	417,701	396,225
Other noncurrent liabilities	415,705	419,771
Total Liabilities	**3,622,002**	**3,823,094**
Commitments and Contingencies (Note 18)		
Shareholders' Equity:		
Common stock, par value $0.01; authorized 200,000,000 shares; issued and outstanding 52,981,246 and 49,372,463, respectively; Preferred stock, par value $0.01; authorized 50,000,000 shares; none issued	530	520
Treasury stock at cost	(96,376)	(95,769)
Paid-in capital	1,445,181	1,384,271
Retained earnings	458,352	396,919
Accumulated other comprehensive loss	(8,772)	(9,714)
Total Shareholders' Equity	**1,798,915**	**1,676,227**
Total Liabilities and Shareholders' Equity	**$ 5,420,917**	**$ 5,499,321**

See Notes to Consolidated Financial Statements

NORTHWESTERN CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2017	2016	2015
OPERATING ACTIVITIES:			
Net Income	$ 162,703	$ 164,172	$ 151,209
Items not affecting cash:			
Depreciation and depletion	166,137	159,336	144,702
Amortization of debt issue costs, discount and deferred hedge gain	4,794	2,117	2,258
Stock-based compensation costs	5,563	6,731	5,082
Equity portion of allowance for funds used during construction	(5,701)	(4,589)	(8,684)
Gain on disposition of assets	(415)	(15)	(20)
Deferred income taxes	12,363	(8,184)	33,886
Changes in current assets and liabilities:			
Restricted cash	870	2,208	6,920
Accounts receivable	(22,726)	(5,146)	9,069
Inventories	(3,226)	4,252	1,636
Other current assets	827	(2,384)	5,514
Accounts payable	3,615	3,639	(11,169)
Accrued expenses	4,844	25,124	(22,738)
Regulatory assets	12,372	1,871	(3,974)
Regulatory liabilities	(11,019)	(54,629)	24,821
Other noncurrent assets	(14,780)	(7,311)	(5,584)
Other noncurrent liabilities	7,387	1,820	6,890
Cash Provided by Operating Activities	323,608	289,012	339,818
INVESTING ACTIVITIES:			
Property, plant, and equipment additions	(276,438)	(287,901)	(283,705)
Acquisitions	—	—	(146,668)
Proceeds from sale of assets	379	1,354	30,209
Change in restricted cash	—	—	16,108
Cash Used in Investing Activities	(276,059)	(286,547)	(384,056)
FINANCING ACTIVITIES:			
Dividends on common stock	(101,270)	(95,765)	(90,058)
Proceeds from issuance of common stock, net	53,669	—	56,651
Issuance of long-term debt	250,000	249,660	270,000
Repayment of long-term debt	(250,000)	(225,205)	(150,025)
Issuances (repayments) of short-term borrowings, net	18,745	70,937	(37,966)
Treasury stock activity	1,083	(561)	(664)
Financing costs	(16,382)	(8,432)	(12,082)
Cash (Used In) Provided by Financing Activities	(44,155)	(9,366)	35,856
Net Increase (Decrease) in Cash and Cash Equivalents	3,394	(6,901)	(8,382)
Cash and Cash Equivalents, beginning of period	5,079	11,980	20,362
Cash and Cash Equivalents, end of period	**$ 8,473**	**$ 5,079**	**$ 11,980**

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, 2014	**50,522**	**3,607**	**$ 505**	**$1,313,844**	**$ (92,558)**	**$ 264,758**	**$ (8,766)**	**$ 1,477,783**
Net income	—	—	—	—	—	151,209	—	151,209
Foreign currency translation adjustment	—	—	—	—	—	—	558	558
Reclassification of net gains on derivative instruments from OCI to net income, net of tax	—	—	—	—	—	—	(698)	(698)
Postretirement medical liability adjustment, net of tax	—	—	—	—	—	—	310	310
Stock based compensation	167	10	—	4,345	(1,856)	—	—	2,489
Issuance of shares	1,100	—	13	58,102	466	—	—	58,581
Dividends on common stock ($1.92 per share)	—	—	—	—	—	(90,058)	—	(90,058)
Balance at December 31, 2015	**51,789**	**3,617**	**$ 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**

(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

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 718,300 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, 2017, 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 approximately $219.5 million through 2024. For further discussion of our gross QF liability, see Note 18 - Commitments and Contingencies. During the years ended December 31, 2017, 2016 and 2015 purchases from this QF were approximately $16.3 million, $25.5 million, and $24.3 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 $2.9 million and $2.9 million at December 31, 2017 and December 31, 2016, respectively. Receivables include unbilled revenues of $89.1 million and $80.4 million at December 31, 2017 and December 31, 2016, respectively.

Inventories

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

	December 31,	
	2017	2016
Materials and supplies	$ 34,630	$ 31,602
Storage gas and fuel	17,802	17,604
Total Inventory	$ 52,432	$ 49,206

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, 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 8 - 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 7.2%, 7.2%, and 7.5%, for Montana and South Dakota for 2017, 2016, and 2015, respectively. AFUDC capitalized totaled $8.5 million, $7.0 million, and $13.6 million for the years ended December 2017, 2016, and 2015, 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 3.3% for 2017, 2016, and 2015, 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, 2017	December 31, 2016
Future QF obligation, net	$ 132,786	$ 134,324
Pension and other employee benefits	111,202	120,122
Customer advances	45,376	40,209
Asset retirement obligations	39,286	39,402
Environmental	29,326	30,501
Other	57,729	55,213
Total Noncurrent Liabilities	$ 415,705	$ 419,771

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

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. 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.

Our revenues are primarily from tariff based sales, which are in the scope of the guidance. 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 will also not have a shift in the timing or pattern of revenue recognition.

Based on our analysis, we did not have a cumulative-effect adjustment to retained earnings at January 1, 2018. Disclosures in 2018 will include a reconciliation of results under the new revenue recognition guidance compared with what would have been reported in 2018 under the old revenue recognition guidance in order to help facilitate comparability with the prior periods. We expect our disclosures to reflect our disaggregated revenue by segment for each geographical region.

Retirement Benefits - In March 2017, the FASB issued new guidance on the presentation of net periodic costs related to benefit plans. The new guidance requires the service cost component of net periodic benefit cost to be included within operating income within the same line as other compensation expenses. All other components of net periodic benefit costs must be outside of operating income. In addition, the updated guidance permits only the service cost component of net periodic benefit costs to be capitalized to inventory or property, plant and equipment. This represents a change from current accounting and financial reporting, with presentation of the aggregate net periodic benefit costs on the income statement within operating income, and which permits all components of net periodic benefit costs to be capitalized.

This guidance is effective for interim and annual periods beginning January 1, 2018. These amendments will be applied retrospectively for the presentation of the various components of net periodic benefit costs and prospectively for the change in eligible costs to be capitalized. 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.

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. The new guidance will be effective for us for interim and annual periods beginning January 1, 2019 and early adoption is permitted. A modified retrospective transition approach is required for lessees for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. An additional transition approach allows an entity to not assess on transition whether any expired or existing land easements are, or contain, leases that were not previously accounted for as leases. We are currently evaluating the impact of adoption of this guidance. We do not have a significant amount of capital or operating leases. Therefore, based on our analysis to this point we do not expect this guidance to have a significant impact on our Consolidated Financial Statements and disclosures other than an expected increase in assets and liabilities.

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. The new guidance will be effective for us in our first quarter of 2018. The adoption of this guidance will not have a significant impact on our Statement of Cash Flows.

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. The new guidance will be effective for us in our first quarter of 2018. The adoption of this guidance will not have a significant impact on our Statement of Cash Flows.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Cash paid (received) for:			
Income taxes	$ 60	$ (2,922)	$ (1,284)
Interest	82,692	84,953	81,572
Significant non-cash transactions:			
Capital expenditures included in trade accounts payable	15,848	13,783	12,834

(3) Regulatory Matters

Montana QF Tariff Filing

Under the Public Utility Regulatory Policies Act (PURPA), electric utilities are required, with exceptions, to purchase energy and capacity from independent power producers that are QFs. In May 2016, we filed an application for approval of a revised tariff for standard rates for small QFs (3 MW or less). In November 2017, the MPSC issued an order revising the QF tariff to establish a maximum contract length of 15 years and substantially lowering the rate for future QF contracts. In this order, the MPSC also upheld an initial decision to apply the contract term to our future owned and contracted electric supply resources.

As a result of this order, we terminated our competitive solicitation process for 20-year resources to determine the lowest-cost / least-risk approach for addressing our intermittent capacity and reserve margin needs in Montana. We continue to evaluate the impact of this decision, as we have significant generation capacity deficits and negative reserve margins, and our 2016 resource plan identified price and reliability risks to our customers if we rely solely upon market purchases to address these capacity needs. In addition to our responsibility to meet peak demand, national reliability standards effective July 2016 require us to have even 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. We expect to file our next electric supply resource procurement plan in late 2018.

Cost Recovery Mechanisms

Montana House Bill 193 / Electric Tracker - In April 2017, the Montana legislature passed House Bill 193 (HB 193), amending the statute that provided for mandatory recovery of our prudently incurred electric supply costs effective July 1, 2017. The revised statute gives the MPSC discretion whether to approve an electric supply cost adjustment mechanism. The MPSC initiated a process to develop a replacement electric supply cost adjustment mechanism, and in response, in July 2017, we filed a proposed electric PCCAM. Intervenor testimony was filed in November 2017, and in December 2017, the MPSC issued a Notice of Additional Issues stating that the range of options proposed by the parties was not sufficient and directing parties to consider alternatives incorporating risk-sharing features of other utilities in the region.

We filed rebuttal testimony in February 2018, responsive to intervenor testimony and the MPSC's December 2017 Notice of Additional Issues addressing alternative risk-sharing mechanisms. A hearing is scheduled to begin May 31, 2018. If the MPSC approves a new mechanism, the MPSC may apply the mechanism to variable costs on a retroactive basis to the effective date of HB 193 (July 1, 2017).

Montana Electric Tracker Open Dockets - 2015/2016 - 2016/2017 - 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. In June 2017, the MPSC consolidated the supply costs portion of the 2016/2017 docket with the 2015/2016 docket. The rates for this consolidated docket were approved on an interim basis. The MPSC has not established a schedule regarding this docket under the prior statutory tracker. In addition, the MPSC consolidated the projected supply costs portion of the 2016/2017 docket with the PCCAM docket, discussed above.

Montana Natural Gas Tracker - 2016/2017 - In May 2017, we filed our annual natural gas tracker filing for the 2016/2017 tracker period, which the MPSC approved on an interim basis. In December 2017, the MPSC issued a final order approving the natural gas interim rates. HB 193 does not impact our natural gas recovery mechanism.

Montana Electric Tracker Litigation - 2012/2013 - 2013/2014 (Consolidated Docket) and 2014/2015 (2015 Tracker) - In 2016, we received two orders in separate electric tracker dockets filed with the MPSC, which, in total, resulted in a $12.4 million disallowance of costs, including interest. The first order (Consolidated Docket) included a disallowance of replacement power costs from a 2013 outage at Colstrip Unit 4 and certain modeling/planning costs. In September 2016, we appealed that order to the Montana District Court, arguing that the order was arbitrary and capricious and violated Montana law. We expect a decision on this appeal within the next 12 months. The second order (2015 Tracker), included a disallowance of certain portfolio modeling costs. In June 2016, we filed an appeal of the second order in Montana District Court arguing that the decision violated Montana law. We expect a decision in the next three to six months.

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 taxes and fees, net of the associated income tax benefit. We submit an annual property tax tracker filing with the MPSC for an automatic rate adjustment, with rates typically effective January 1st of each year. The MPSC identified concerns with the amount of annual increases proposed by the Montana Department of Revenue. In June 2017, the MPSC adopted new rules to establish minimum filing requirements for our statutory property tax tracker filing. Some of the rules appear to be based on a narrow interpretation of the statutory language and suggest that the MPSC will challenge the amount and allocation of these taxes to customers. We filed our annual property tax tracker filing in December 2017. In January 2018, the MPSC issued an order in our 2017 filing reducing our recovery of these taxes by approximately$1.7 million by applying an alternate allocation methodology. This results in a lower allocation to our Montana electric retail customers and a higher property tax allocation to FERC transmission customers (we do not have a property tax tracker for FERC jurisdictional purposes). We submitted a motion for reconsideration of this order on February 8, 2018, and expect a decision by the end of the first quarter of 2018.

Tax Cuts and Jobs Act

The MPSC and SDPUC initiated dockets regarding the impact of the Tax Cuts and Jobs Act on customer rates beginning January 1, 2018. We are required to submit filings in Montana and South Dakota during the first quarter of 2018 with a proposal to address the effects of the lower statutory rate. We expect to provide a customer benefit as a result of the Tax Cuts and Jobs Act in each of our jurisdictions.

FERC Filing - Dave Gates Generating Station at Mill Creek (DGGS)

In May 2016, we received an order from the FERC denying a May 2014 request for rehearing and requiring us to make refunds. The request for rehearing challenged a September 2012 FERC Administrative Law Judge's (ALJ) initial decision regarding cost allocation at DGGS between retail and wholesale customers. The 2012 decision concluded that only a portion of these costs should be allocated to FERC jurisdictional customers. We had cumulative deferred revenue of approximately $27.3 million, consistent with the ALJ's initial decision, which was refunded to wholesale and choice customers in June 2016 in accordance with the FERC order.

In June 2016, we filed a petition for review of the FERC's May 2016 order with the United States Circuit Court of Appeals for the District of Columbia Circuit (D.C. Circuit). A hearing was held on December 1, 2017. We expect a decision in this matter by the end of the second quarter of 2018.

(4) 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,	
	Note Reference	Remaining Amortization Period	2017	2016
			(in thousands)	
Income taxes	12	Plant Lives	$ 163,605	$ 411,546
Pension	14	Undetermined	115,504	127,133
Deferred financing costs		Various	37,090	24,810
Employee related benefits	14	Undetermined	17,729	20,256
Supply costs		1 Year	13,398	16,809
State & local taxes & fees		Various	10,896	17,838
Environmental clean-up	18	Various	12,399	13,601
Distribution infrastructure projects		-	—	3,136
Other	—	Various	21,364	17,855
Total Regulatory Assets			**$ 391,985**	**$ 652,984**
Removal cost	6	Various	$ 408,451	$ 386,373
Supply costs		1 Year	10,357	14,041
Gas storage sales		22 Years	9,149	9,569
Deferred revenue	3	1 Year	2,201	5,066
State & local taxes & fees		1 Year	1,520	1,154
Environmental clean-up		Various	1,365	6,383
Total Regulatory Liabilities			**$ 433,043**	**$ 422,586**

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. This reflects the estimated impact of the Tax Cuts and Job Acts enacted in December 2017. See Note 12 - 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 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. The MPSC allows recovery of other employee related benefits on a cash 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 electric and natural gas supply costs under collected, or apply interest in an over collection, of 7.9% and 7.0%, respectively, in Montana; 7.2% and 7.8%, 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 18 - 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.

Montana Distribution System Infrastructure Project (DSIP)

We have an accounting order to defer certain incremental operating and maintenance expenses associated with DSIP. Pursuant to the order, we deferred expenses incurred during 2011 and 2012 as a regulatory asset associated with the phase-in portion of the DSIP. These costs are being amortized into expense over five years, which began in 2013 and concluded in 2017.

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 6 - Asset Retirement Obligations, for further information regarding this item.

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.

Deferred Revenue

We have deferred revenue associated with DGGS and Gas Production, which may be subject to refund as we have open regulatory proceedings. See Note 3 - Regulatory Matters, for further information regarding these items.

(5) Property, Plant and Equipment

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

	Estimated Useful Life	December 31, 2017	December 31, 2016
	(years)	(in thousands)	
Land, land rights and easements	53 – 96	$ 148,507	$ 138,963
Building and improvements	27 – 64	242,038	225,003
Transmission, distribution, and storage	15 – 85	3,163,463	2,933,788
Generation	25 – 50	1,187,346	1,167,525
Plant acquisition adjustment	25 – 50	685,417	685,417
Other	2 – 45	521,711	472,264
Construction work in process	—	69,902	116,995
Total property, plant and equipment		6,018,384	5,739,955
Less accumulated depreciation		(1,660,119)	(1,525,063)
Net property, plant and equipment		$ 4,358,265	$ 4,214,892

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 $17.5 million and $19.3 million as of December 31, 2017 and 2016, respectively, which included $17.1 million and $19.1 million as of December 31, 2017 and 2016, 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, 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
December 31, 2016				
Ownership percentages	23.4%	8.7%	10.0%	30.0%
Plant in service	$ 153,623	$ 60,491	$ 50,802	$ 297,289
Accumulated depreciation	38,894	29,235	37,099	77,513

(6) 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 ARO 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, and our obligation to plug and abandon oil and gas wells at the end of their life. The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2017	2016
Liability at January 1,	$ 39,402	$ 35,532
Accretion expense	2,062	1,885
Liabilities incurred	—	164
Liabilities settled	(61)	—
Revisions to cash flows	(2,117)	1,821
Liability at December 31,	$ 39,286	$ 39,402

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 4 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2017 and 2016.

(7) Goodwill

We completed our annual goodwill impairment test as of April 1, 2017 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,	
	2017	2016
Electric	$ 243,558	$ 243,558
Natural gas	114,028	114,028
Total Goodwill	$ 357,586	$ 357,586

(8) 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, 2017 and 2016. 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, 2017
Interest rate contracts	Interest Expense	$ 613

A pre-tax loss of approximately $16.5 million is remaining in AOCL as of December 31, 2017, 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.

(9) 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 8 - 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, 2017	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	$ 2,648	$ —	$ —	$ —	$ 2,648
Rabbi trust investments	28,135	—	—	—	28,135
Total	**$ 30,783**	**$ —**	**$ —**	**$ —**	**$ 30,783**
December 31, 2016					
Restricted cash	$ 4,164	$ —	$ —	$ —	$ 4,164
Rabbi trust investments	25,064	—	—	—	25,064
Total	**$ 29,228**	**$ —**	**$ —**	**$ —**	**$ 29,228**

Restricted cash 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, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 1,793,416	$ 1,901,915	$ 1,793,338	$ 1,852,052

Short-term borrowings 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.

(10) Short-Term Borrowings and Credit Arrangements

Short-Term Borrowings

Short-term borrowings and the corresponding weighted average interest rates as of December 31 were as follows (dollars in millions):

	2017		2016	
Short-Term Debt	**Balance**	**Interest Rate**	**Balance**	**Interest Rate**
Commercial Paper	$ 319.6	1.75%	$ 300.8	1.07%

The following information relates to commercial paper for the years ended December 31 (dollars in millions):

	2017	2016
Maximum short-term debt outstanding	$ 332.5	$ 300.8
Average short-term debt outstanding	$ 251.7	$ 210.7
Weighted-average interest rate	1.35%	0.86%

Under our commercial paper program we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $340 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility.

Unsecured Revolving Line of Credit

On December 12, 2016, we amended and restated our existing revolving credit facility to, among other things, increase the size of the facility to $400 million (from $350 million) and extend the maturity date to December 12, 2021 (from November 5, 2018). We retained 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 or available rates tied to the Eurodollar rate plus a credit spread, ranging from 0.875% to 1.75%. A total of eight banks participate in the facility, with no one bank providing more than 16% of the total availability. There were no direct borrowings or letters of credit outstanding as of December 31, 2017. Commitment fees for the unsecured revolving line of credit were $0.5 million and $0.4 million for the years ended December 31, 2017 and 2016.

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

(11) Long-Term Debt and Capital Leases

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

		December 31,	
	Due	2017	2016
Unsecured Debt:			
Unsecured Revolving Line of Credit	2021	$ —	$ —
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—6.34%	2019	—	250,000
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	—
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	—	(13,221)	(13,299)
		$ 1,793,416	$ 1,793,338
Less current maturities		—	—
Total Long-Term Debt		$ 1,793,416	$ 1,793,338
Capital Leases:			
Total Capital Leases	Various	$ 24,346	$ 26,325
Less current maturities		(2,133)	(1,979)
Total Long-Term Capital Leases		$ 22,213	$ 24,346

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.

In August 2016, the City of Forsyth, Rosebud County, Montana issued $144.7 million aggregate principal amount of Pollution Control Revenue Refunding Bonds on our behalf. The bonds were issued at a fixed interest rate of 2.00% maturing in 2023. The proceeds of the issuance were loaned to us pursuant to a Loan Agreement and have been used to partially fund the redemption of the 4.65%, $170.2 million City of Forsyth Pollution Control Revenue Refunding Bonds due 2023 (Prior Bonds) issued on our behalf. We paid the remaining portion of the Prior Bonds with available funds. Our obligation under the Loan Agreement is secured by the issuance of $144.7 million of Montana First Mortgage Bonds. These bonds are secured by our electric and natural gas assets in Montana and Wyoming. The City of Forsyth bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended.

In June 2016, we issued $60 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 2.80% maturing in 2026. Proceeds were used to redeem our 6.05%, $55 million South Dakota First Mortgage Bonds due 2018. In addition, in September 2016, we issued $45.0 million aggregate principal amount of South Dakota First Mortgage Bonds at a fixed interest rate of 2.66% maturing in 2026. Proceeds from this issuance were used for general corporate purposes. Both series of these bonds are secured by our electric and natural gas assets in South Dakota, Nebraska, North Dakota, and Iowa and were issued in transactions exempt from the registration requirements of the Securities Act of 1933, as amended.

As of December 31, 2017, 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 $2.1 million in 2018, $2.3 million in 2019, $2.5 million in 2020, $2.7 million in 2021 and $2.9 million in 2022.

(12) Income Taxes

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

	Year Ended December 31, 2017	2016	2015
Federal			
Current	$ 806	$ 723	$ (3,527)
Deferred	17,378	(2,054)	33,031
Investment tax credits	166	(196)	(232)
State			
Current	33	10	(90)
Deferred	(5,015)	(6,130)	855
Income Tax Expense (Benefit)	$ 13,368	$ (7,647)	$ 30,037

The following table reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31, 2017	2016	2015
Federal statutory rate	35.0%	35.0 %	35.0%
State income tax, net of federal provisions	(1.9)	(2.4)	0.1
Flow-through repairs deductions	(17.3)	(26.3)	(13.3)
Production tax credits	(6.3)	(7.0)	(3.2)
Plant and depreciation of flow through items	(1.3)	(2.9)	(1.6)
Share-based compensation	(0.2)	(1.1)	—
Prior year permanent return to accrual adjustments	(0.3)	(0.1)	0.1
Other, net	(0.1)	(0.1)	(0.5)
Effective tax rate	7.6%	(4.9)%	16.6%

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

	Year Ended December 31, 2017	2016	2015
Income Before Income Taxes	176,071	156,525	181,246
Income tax calculated at 35% federal statutory rate	61,625	54,784	63,436
Permanent or flow through adjustments:			
State tax income, net of federal provisions	(3,258)	(3,714)	301
Flow-through repairs deductions	(30,490)	(41,111)	(24,079)
Production tax credits	(11,032)	(10,941)	(5,721)
Plant and depreciation of flow through items	(2,208)	(4,604)	(2,893)
Share-based compensation	(363)	(1,646)	—
Prior year permanent return to accrual adjustments	(629)	(128)	207
Other, net	(277)	(287)	(1,214)
	(48,257)	(62,431)	(33,399)
Income Tax Expense (Benefit)	13,368	(7,647)	30,037

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.

Tax Cuts and Jobs Act

On December 22, 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. We revalued our net deferred tax liability as of December 31, 2017 based on the reduction in the overall future tax impact expected to be realized at the lower tax rate. This resulted in a reduction in our net deferred tax liability of approximately $321 million, which was offset in regulatory assets and liabilities.

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 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,	
	2017	**2016**
NOL carryforward	$ 68,840	$ 72,964
Production tax credit	28,067	17,034
Pension / postretirement benefits	26,887	45,847
AMT credit carryforward	13,599	13,599
Compensation accruals	12,113	18,715
Customer advances	11,949	15,837
Unbilled revenue	5,944	12,743
Environmental liability	5,821	9,698
Interest rate hedges	4,323	7,192
Reserves and accruals	1,126	1,121
Property taxes	432	3,767
QF obligations	234	1,025
Regulatory liabilities	114	2,290
Other, net	1,138	3,173
Deferred Tax Asset	**180,587**	**225,005**
Excess tax depreciation	(356,938)	(459,588)
Goodwill amortization	(117,971)	(168,165)
Flow through depreciation	(45,998)	(160,604)
Regulatory assets	(409)	(12,230)
Deferred Tax Liability	**(521,316)**	**(800,587)**
Deferred Tax Liability, net	**$ (340,729)**	**$ (575,582)**

The revaluation of deferred income taxes reflects our estimate of the impact of the Tax Cuts and Jobs Act. We will continue to evaluate subsequent regulations and interpretations and assumptions made, which could materially change our estimate. Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. We have elected under Internal Revenue Code Section 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

At December 31, 2017 we estimate our total federal NOL carryforward to be approximately $420.8 million prior to consideration of unrecognized tax benefits. If unused, our federal NOL carryforwards will expire as follows: $105.2 million in 2031; $13.3 million in 2033; $73.3 million in 2034; $174.6 million in 2036 and $54.4 million in 2037. We estimate our state NOL carryforward as of December 31, 2017 is approximately $315.7 million. If unused, our state NOL carryforwards will expire as follows: $67.0 million in 2018; $10.5 million in 2020; $58.3 million in 2021; $135.9 million in 2023 and $44.0 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):

	2017	2016	2015
Unrecognized Tax Benefits at January 1	$ 88,429	$ 92,387	$ 95,929
Gross increases - tax positions in prior period	—	—	44
Gross decreases - tax positions in prior period	(22,973)	—	(2,903)
Gross increases - tax positions in current period	—	—	494
Gross decreases - tax positions in current period	(7,983)	(3,958)	(1,177)
Lapse of statute of limitations	—	—	—
Unrecognized Tax Benefits at December 31	$ 57,473	$ 88,429	$ 92,387

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 $47.8 million and $66.5 million related to tax positions as of December 31, 2017 and 2016, respectively that, if recognized, would impact our annual effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the years ended December 31, 2017 and 2016, we recognized $0.8 million and $0.7 million, respectively, of expense for interest and penalties in the Consolidated Statements of Income. As of December 31, 2017 and 2016, we had $1.5 million and $0.7 million, respectively, of interest accrued in the Consolidated Balance Sheets.

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

(13) 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,								
	2017			2016			2015		
	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	$ (202)	$ —	$ (202)	$ 25	—	$ 25	$ 558	$ —	$ 558
Reclassification of net losses (gains) on derivative instruments	613	(242)	371	(2,169)	831	(1,338)	(1,125)	427	(698)
Postretirement medical liability adjustment	1,257	(484)	773	317	(122)	195	504	(194)	310
Other comprehensive income (loss)	$ 1,668	$ (726)	$ 942	$ (1,827)	$ 709	$ (1,118)	$ (63)	$ 233	$ 170

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

	December 31,	
	2017	2016
Foreign currency translation	$ 1,178	$ 1,380
Derivative instruments designated as cash flow hedges	(9,981)	(10,352)
Postretirement medical plans	31	(742)
Accumulated other comprehensive loss	$ (8,772)	$ (9,714)

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

	Affected Line Item in the Consolidated Statements of Income	Year Ended December 31, 2017 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 income (loss)		371	773	(202)	942
Ending Balance		$ (9,981)	$ 31	$ 1,178	$ (8,772)

	Affected Line Item in the Consolidated Statements of Income	Year Ended December 31, 2016 Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,014)	$ (937)	$ 1,355	$ (8,596)
Other comprehensive income before reclassifications		—	—	25	25
Amounts reclassified from AOCL	Interest Expense	(1,338)	—	—	(1,338)
Amounts reclassified from AOCL		—	195	—	195
Net current-period other comprehensive (loss) income		(1,338)	195	25	(1,118)
Ending Balance		$ (10,352)	$ (742)	$ 1,380	$ (9,714)

(14) 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. 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 4 - 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,	
	2017	2016	2017	2016
Change in benefit obligation:				
Obligation at beginning of period	$ 646,032	$ 628,883	$ 26,217	$ 28,652
Service cost	10,994	11,759	456	492
Interest cost	25,633	26,210	715	795
Actuarial loss (gain)	41,719	7,006	(1,884)	(71)
Settlements	—	—	390	390
Benefits paid	(27,582)	(27,826)	(2,973)	(4,041)
Benefit Obligation at End of Period	$ 696,796	$ 646,032	$ 22,921	$ 26,217
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 524,637	$ 500,044	$ 18,605	$ 17,972
Return on plan assets	80,253	39,719	2,690	1,277
Employer contributions	9,200	12,700	2,058	3,397
Benefits paid	(27,582)	(27,826)	(2,973)	(4,041)
Fair value of plan assets at end of period	$ 586,508	$ 524,637	$ 20,380	$ 18,605
Funded Status	$ (110,288)	$ (121,395)	$ (2,541)	$ (7,612)
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	2,535	—	5,061	—
Total Assets	2,535	—	5,061	—
Current liability	—	—	(3,353)	(1,789)
Noncurrent liability	(112,823)	(121,395)	(4,249)	(5,823)
Total Liabilities	(112,823)	(121,395)	(7,602)	(7,612)
Net amount recognized	$ (110,288)	$ (121,395)	$ (2,541)	$ (7,612)
Amounts Recognized in Regulatory Assets Consist of:				
Prior service (cost) credit	(4)	(9)	9,955	11,988
Net actuarial loss	(105,545)	(127,953)	(1,735)	(4,739)
Amounts recognized in AOCL consist of:				
Prior service cost	—	—	(698)	(849)
Net actuarial gain	—	—	1,079	38
Total	$ (105,549)	$ (127,962)	$ 8,601	$ 6,438

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):

	Pension Benefits	
	December 31,	
	2017	2016
Projected benefit obligation	$ 634.4	$ 646.0
Accumulated benefit obligation	634.4	643.6
Fair value of plan assets	522.7	524.6

As of December 31, 2017, 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,		
	2017	2016	2015	2017	2016	2015
Components of Net Periodic Benefit Cost						
Service cost	$ 10,994	$ 11,759	$ 12,362	$ 456	$ 492	$ 526
Interest cost	25,633	26,210	26,174	715	795	786
Expected return on plan assets	(23,964)	(28,248)	(31,561)	(846)	(1,042)	(969)
Amortization of prior service cost (credit)	4	246	246	(1,882)	(1,882)	(1,882)
Recognized actuarial loss	7,837	9,888	10,634	318	315	385
Settlement loss recognized	—	—	—	390	390	390
Net Periodic Benefit Cost (Credit)	$ 20,504	$ 19,855	$ 17,855	$ (849)	$ (932)	$ (764)

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.

We estimate amortizations from regulatory assets into net periodic benefit cost during 2018 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service credit (cost)	$ (4)	$ 1,882
Accumulated loss	(4,286)	78

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2017 and 2016. 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.

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 decrease in discount rate during 2017 increased our projected benefit obligation by approximately $43.6 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 4.97% and decreased our assumption on the NorthWestern Corporation Pension Plan to 4.47% for 2018.

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

	Pension Benefits			Other Postretirement Benefits		
	December 31,			December 31,		
	2017	2016	2015	2017	2016	2015
Discount rate	3.50-3.60 %	3.95-4.10 %	4.15-4.30 %	3.20-3.30 %	3.40-3.55 %	3.60-3.75 %
Expected rate of return on assets	4.70	5.80	5.80	4.70	5.80	5.80
Long-term rate of increase in compensation levels (nonunion)	2.89	3.28	3.58	2.89	3.28	3.58
Long-term rate of increase in compensation levels (union)	2.03	3.20	3.50	2.03	3.20	3.50

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 fully 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,	
	2017	2016	2017	2016	2017	2016
Domestic debt securities	55.0%	55.0%	70.0%	65.0%	40.0%	40.0%
International debt securities	4.0	5.0	2.5	5.0	—	—
Domestic equity securities	16.5	34.0	11.0	25.0	50.0	50.0
International equity securities	24.5	6.0	16.5	5.0	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,	
	2017	2016	2017	2016	2017	2016
Cash and cash equivalents	0.1%	—%	—%	0.1%	1.5%	1.0%
Domestic debt securities	54.5	53.4	70.0	64.4	35.2	37.0
International debt securities	4.0	4.6	2.5	4.4	—	—
Domestic equity securities	16.7	36.0	11.1	26.0	53.4	52.6
International equity securities	24.7	6.0	16.4	5.1	9.9	9.4
	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 2018 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 2017, 2016 and 2015 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2017	2016	2015
NorthWestern Energy Pension Plan (MT)	$ 8,000	$ 11,500	$ 9,000
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200	1,200
	$ 9,200	$ 12,700	$ 10,200

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

	Pension Benefits	Other Postretirement Benefits
2018	$ 30,326	$ 3,353
2019	31,721	2,927
2020	33,452	2,714
2021	34,703	2,502
2022	35,997	2,254
2023-2027	200,820	7,607

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, 2017, 2016 and 2015 were $10.0 million, $9.8 million, and $9.5 million.

(15) 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, 2017, there were 822,695 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:

	2017	2016
Risk-free interest rate	1.50%	0.85%
Expected life, in years	3	3
Expected volatility	17.0% to 22.7%	17.1% to 22.1%
Dividend yield	3.7%	3.4%

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, 2017, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	175,257	$ 46.35
Granted	93,108	47.99
Vested	(87,438)	42.47
Forfeited	(5,459)	47.60
Remaining nonvested grants	175,468	$ 49.11

We recognized compensation expense of $3.9 million, $5.3 million, and $4.4 million for the years ended December 31, 2017, 2016, and 2015, respectively, and a related income tax expense of $0.4 million, $1.8 million, and $1.8 million for the years ended December 31, 2017, 2016, and 2015, respectively. As of December 31, 2017, we had $5.5 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 $3.7 million, $3.5 million, and $2.8 million for the years ended December 31, 2017, 2016 and 2015, 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, 2017, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	62,591	$ 41.14
Granted	13,394	52.20
Vested	(8,445)	27.42
Forfeited	—	—
Remaining nonvested grants	67,540	$ 43.09

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, 2017, 2016 and 2015, DSUs issued to members of our Board totaled 54,920, 28,338 and 35,030, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2017, 2016 and 2015 was approximately $2.9 million, $2.4 million and $1.3 million, respectively.

(16) 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 15 - 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 may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $100 million. During 2017, we sold 888,938 shares of our common stock at an average price of $61.30 per share. Proceeds received were approximately $53.7 million, which are net of sales commissions paid of approximately $0.8 million and other fees. During the three months ended December 31, 2017, we issued 805,169 shares at an average price of $61.48, for net proceeds of $48.9 million, which is net of sales commissions of approximately $0.6 million and other fees.

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 34,208 and 49,514 during the years ended December 31, 2017 and 2016, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

(17) 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,	
	2017	2016
Basic computation	48,557,599	48,298,896
Dilutive effect of		
Performance and restricted share awards (1)	97,722	176,166
Diluted computation	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.

(18) 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 $61 to $136 per MWH through 2029. Our estimated gross contractual obligation related to these contracts is approximately $807.4 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $625.6 million through 2029. 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,	
	2017	2016
Beginning QF liability	$ 134,324	$ 138,310
Unrecovered amount	(12,009)	(14,829)
Interest expense	10,471	10,843
Ending QF liability	$ 132,786	$ 134,324

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

	Gross Obligation	Recoverable Amounts	Net
2018	76,703	58,401	18,302
2019	78,836	59,020	19,816
2020	80,984	59,647	21,337
2021	82,941	60,136	22,805
2022	84,948	60,639	24,309
Thereafter	403,009	327,773	75,236
Total	$ 807,421	$ 625,616	$ 181,805

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 26 years. Costs incurred under these contracts are included in Cost of Sales in the Consolidated Statements of Income and were approximately $228.4 million, $216.8 million and $241.6 million for the years ended December 31, 2017, 2016, and 2015, respectively. As of December 31, 2017, our commitments under these contracts are $190.6 million in 2018, $179.0 million in 2019, $134.8 million in 2020, $113.9 million in 2021, $116.0 million in 2022, and $1.3 billion thereafter. These commitments are not reflected in our Consolidated Financial Statements.

Hydroelectric License Commitments

With the Hydro Transaction, 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 $20.0 million between 2018 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, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us and is estimated to range between $26.7 million to $31.2 million. As of December 31, 2017, we have a reserve of approximately $30.3 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 $23.5 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, 2017, the reserve for remediation costs at this site is approximately $9.6 million, and we estimate that approximately $4.6 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 September 2017, we submitted a Draft Remedial Investigation Work Plan for the Helena site, based on the request of the MDEQ. Comments from the MDEQ are expected in the first quarter of 2018.

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, carbon dioxide (CO_2). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, actions at the state level, 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 Clean Power Plan, 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.

As a result of the Executive Order review, on October 10, 2017, the EPA proposed to repeal the Clean Power Plan (CPP). Subsequently, the EPA issued an Advance Notice of Proposed Rulemaking, soliciting information on systems of emission reduction that comply with EPA's interpretation of the Clean Air Act, for a possible replacement of the CPP, which was published in the Federal Register on December 28, 2017. 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 CO2 emission performance standards for existing electric utility steam generating units and natural gas combined cycle units. In its repeal proposal, EPA indicated that it had not yet determined whether it will promulgate a new rule to replace the CPP and the form, if any, such a replacement would take.

Following the issuance of the CPP in October 2015, judicial appeals were filed in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), including an appeal by us. The United States Supreme Court (Supreme Court) issued a stay pending resolution of the appeals by the D.C. Circuit. The D.C. Circuit filed an order on November 9, 2017, holding the case in abeyance for 60 days. On January 10, 2018, EPA filed a status report requesting the D.C. Circuit continue to hold the case in abeyance pending conclusion of its rulemaking.

In addition, administrative requests for reconsideration of the CPP were filed with the EPA, including one filed by us in December 2015. We requested the EPA reconsider the CPP, in part, on the grounds that the CO_2 reductions in the CPP applicable to Montana were substantially greater than the reductions the EPA had originally proposed. The EPA denied the petition for reconsideration on January 11, 2017, and we appealed that denial to the D.C. Circuit on March 13, 2017. The EPA has also requested that this case be held in abeyance.

We cannot predict what, if any, action the D.C. Circuit may take in either of these two cases, particularly in light of the EPA's proposal to repeal the CPP. If the CPP ultimately is not repealed, survives the legal challenges described above, and is implemented as written, or if a replacement to the CPP is adopted with similar requirements, it could result in significant additional compliance costs that would 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 impacts 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 EPA has not responded to our petition. On January 19, 2018, EPA advised the D.C. Circuit that it intended to initiate rulemaking to revisit the amendment, and asked that the case be held in abeyance. On January 30, 2018, the D.C. Circuit granted the EPA's request to hold the case in abeyance pending further order of the Court.

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, 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 repealing or significantly changing the CPP.

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

Billings, Montana Refinery Outage Claim

On January 25, 2014, an electrical outage on our 50kV lines supplying power to the ExxonMobil refinery in Billings, Montana caused the refinery to shut down for an extended period. On January 13, 2016, a second electrical outage shut down the ExxonMobil refinery for about nine days. On January 22, 2016, ExxonMobil filed suit against NorthWestern in U.S.

District Court in Billings, Montana, seeking unspecified compensatory and punitive damages arising from both outages. ExxonMobil claimed property damages and economic losses of approximately $84.9 million to $95.6 million. We reported the refinery's claims and lawsuit to our liability insurance carriers under our liability insurance coverage, which has a $2.0 million per occurrence retention. We also brought third-party complaints against the City of Billings and General Electric International, Inc. alleging that they were responsible in whole or in part for the outages.

Following the completion of fact and expert witness discovery, the parties participated in mediation on November 16, 2017, which resulted in a settlement of all claims. The parties filed a stipulation for dismissal with prejudice, and on December 21, 2017, the court dismissed all claims and third-party claims with prejudice and ordered each party to pay their own costs and fees. Our liability insurance carriers have reimbursed us for the amount of the settlement, less our retention amounts.

Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is an Oregon solar QF developer with which we began negotiating in early 2016 to purchase capacity and energy at our avoided cost under the QF-1 option 1(a) standard rates in accordance with PURPA as implemented by the FERC and the MPSC.

On June 16, 2016, however, the MPSC entered a Notice of Commission Action (MPSC Notice) suspending the availability of QF-1 option 1(a) standard rates for solar projects greater than 100 kW, which included the various projects proposed by PNWS. The MPSC exempted from the suspension any contracts at the standard tariff rate with solar QFs greater than 100 kW, but no larger than 3 MW, if prior to the date of the MPSC Notice, the QF had submitted a signed power purchase agreement and had executed an interconnection agreement. PNWS had not obtained interconnection agreements for any of its projects as of June 16, 2016, so based on the MPSC Notice and subsequent July 25, 2016 Order 7500 of like effect from the MPSC, we discontinued further negotiations with PNWS.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and other relief, including a judicial declaration that some or all of the 21 proposed power purchase agreements were in effect. We removed the state lawsuit to the United States District Court for the District of Montana.

On July 19, 2017, we entered into a partial settlement agreement with PNWS that resolved some but not all of PNWS' litigation claims. As a result of that settlement, on August 14, 2017, PNWS amended its original complaint to include four, rather than 21, power purchase agreements.

Currently pending before the United States District Court are our motion to dismiss, our motion for partial summary judgment, and PNWS's motion for summary judgment on its request for declaratory relief regarding the four power purchase agreements.

We dispute the remaining claims in PNWS' 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.

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 as defendants. The State claims 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 in the litigation 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 and following briefing and argument, on October 10, 2017, the Federal District Court Judge entered an order denying the State's motion. As 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. The motions to dismiss have been fully briefed and are awaiting decision.

We dispute the State's claims and intend to vigorously defend the lawsuit. This matter is in the initial stages, and we cannot predict an outcome. If the Federal District Court determines the riverbeds under all 10 of the hydroelectric facilities are navigable (including the five hydroelectric facilities on the Great Falls Reach) and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $7 million commencing in November 2014, when we acquired the facilities. 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 Claims

On October 10, 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 us in the Montana Eighth Judicial District Court (Eighth District Court). The Wilde lawsuit alleges 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 Wilde lawsuit also seeks compensatory damages of not less than $4.8 million, various forms of declaratory relief, injunctive relief, unspecified damages, and punitive damages.

On October 20, 2017, the Eighth District Court conducted a hearing on the Wilde plaintiffs' application for a preliminary injunction to stop the defendants from the alleged ongoing discrimination that harms development of renewable energy in Montana. At the hearing's conclusion, the court did not rule on the requested injunction but orally ordered post-hearing briefs. On November 11, 2017, Mr. Wilde died in a farming accident, and the Eighth District Court subsequently issued a stay in the proceeding through February 13, 2018. The plaintiff's attorney has asked for an additional 60-day stay. We have received no indication whether or not Mr. Wilde's estate or the other plaintiff entities will continue the litigation after the stay expires.

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.

(19) 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.

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, 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	223,474	81,620	43	—	305,137
Property and other taxes	127,391	35,214	9	—	162,614
Depreciation and depletion	136,556	29,548	33	—	166,137
Operating income (loss)	215,603	45,897	(85)	—	261,415
Interest expense, net	(82,454)	(5,920)	(3,889)	—	(92,263)
Other income, net	3,984	1,985	950	—	6,919
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	216,736	86,713	(556)	—	302,893
Property and other taxes	115,583	32,505	10	—	148,098
Depreciation and depletion	130,236	29,067	33	—	159,336
Operating income	216,223	29,211	513	—	245,947
Interest expense, net	(86,038)	(6,589)	(2,343)	—	(94,970)
Other income, net	3,246	1,329	973	—	5,548
Income tax benefits (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

December 31, 2015	Electric	Gas	Other	Eliminations	Total
Operating revenues	$ 944,428	$ 269,871	$ —	$ —	$ 1,214,299
Cost of sales	281,251	91,613	—	—	372,864
Gross margin	663,177	178,258	—	—	841,435
Operating, general and administrative	233,416	84,219	(20,160)	—	297,475
Property and other taxes	104,264	29,168	10	—	133,442
Depreciation and depletion	115,701	28,968	33	—	144,702
Operating income	209,796	35,903	20,117	—	265,816
Interest expense, net	(79,044)	(11,433)	(1,676)	—	(92,153)
Other income, net	6,300	1,821	(538)	—	7,583
Income tax expense	(19,950)	(3,752)	(6,335)	—	(30,037)
Net income	$ 117,102	$ 22,539	$ 11,568	$ —	$ 151,209
Total assets	$ 4,185,192	$ 1,072,613	$ 6,890	$ —	$ 5,264,695
Capital expenditures	$ 234,451	$ 49,254	$ —	$ —	$ 283,705

(20) 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:

2017	First	Second	Third	Fourth
Operating revenues	$ 367,312	$ 283,859	$ 309,933	$ 344,548
Operating income	85,144	43,695	61,546	71,030
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
Dividends per share	$ 0.525	$ 0.525	$ 0.525	$ 0.525
Stock price:				
High	$ 59.41	$ 63.86	$ 61.80	$ 64.47
Low	55.65	58.16	56.87	56.44
Quarter-end close	58.70	61.02	56.94	59.70

2016	First	Second	Third	Fourth
Operating revenues	$ 332,539	$ 293,120	$ 300,998	$ 330,590
Operating income	61,933	63,742	56,116	64,156
Net income (1)	$ 39,867	$ 35,569	$ 44,605	$ 44,131
Average common shares outstanding	48,242	48,309	48,315	48,329
Income per average common share:				
Basic	$ 0.83	$ 0.74	$ 0.92	$ 0.91
Diluted	$ 0.82	$ 0.73	$ 0.92	$ 0.92
Dividends per share	$ 0.50	$ 0.50	$ 0.50	$ 0.50
Stock price:				
High	$ 62.22	$ 63.30	$ 63.75	$ 59.13
Low	52.16	55.34	56.18	53.85
Quarter-end close	61.75	63.07	57.53	56.87

(1) We adopted the provisions of ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, during the fourth quarter of 2016, which resulted in the recognition of $1.8 million in excess tax benefits. In accordance with the guidance, the $1.8 million impact of this adoption is reflected as of January 1, 2016, which resulted in an increase in net income and earnings per share for the three months ended March 31, 2016 above.

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, 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
FOR THE YEAR ENDED DECEMBER 31, 2015				
RESERVES DEDUCTED FROM APPLICABLE ASSETS				
Uncollectible accounts	4,302	2,322	(2,625)	3,999