READY.

2018 Annual Report | Proxy Statement | Form 10-K

Black Hills Corporation

Ready

BKH 2018 | Black Hills Corporation | Annual Report | Proxy Statement | Form 10-K

www.blackhillscorp.com

BLACK HILLS CORPORATION

We are a customer focused, growth-oriented utility company with a tradition of exemplary service and a vision to be the energy partner of choice. Based in Rapid City, South Dakota, the company serves 1.27 million electric and natural gas utility customers in 823 communities in Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. Employees partner to produce results that Improve Life with Energy.

Arkansas
172,000 utility customers
100 communities served

Colorado
283,400 utility customers
119 communities served
537 megawatts of owned power generation capacity

Iowa
158,500 utility customers
133 communities served

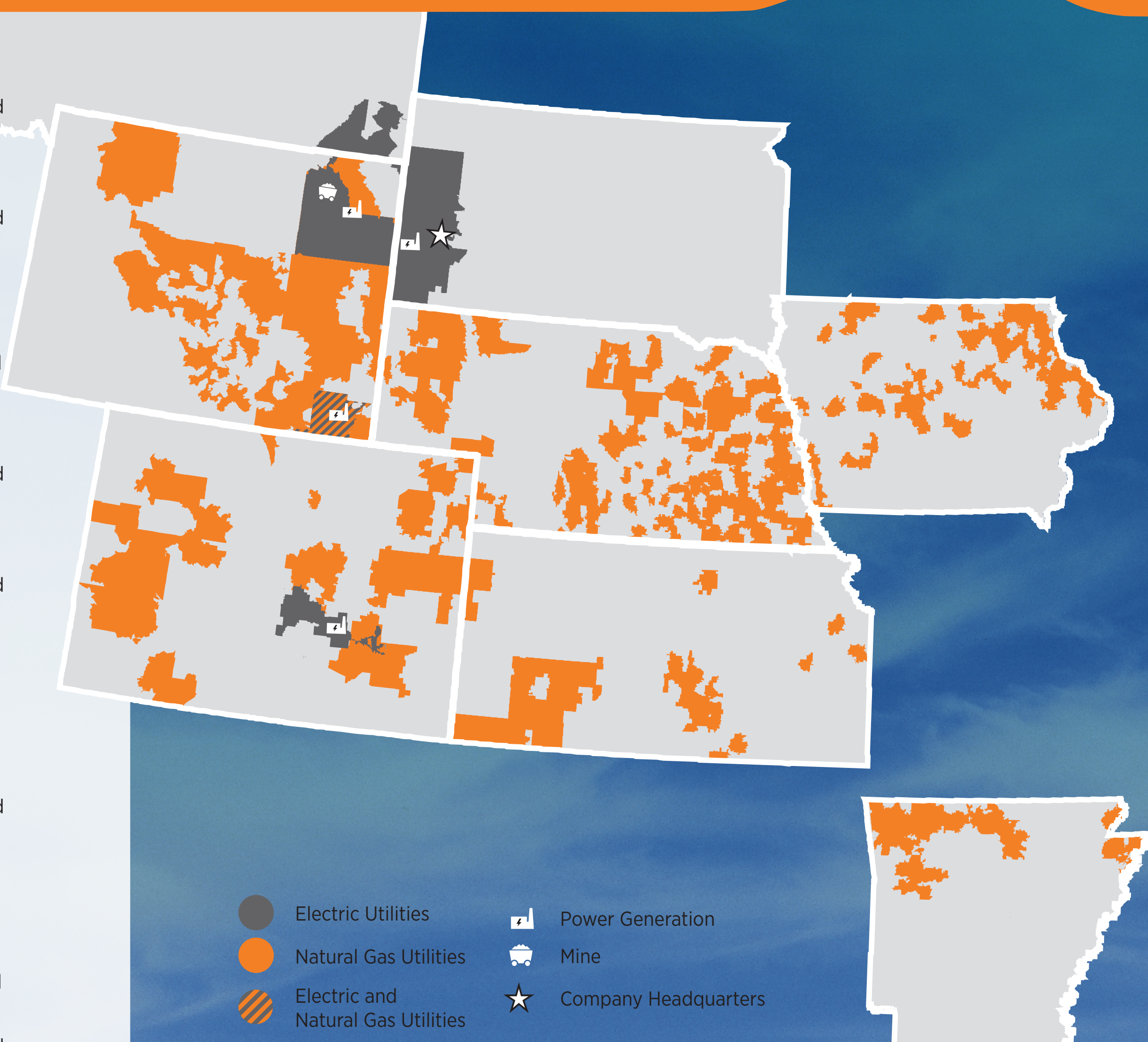
Kansas
114,800 utility customers
65 communities served

Montana
45 utility customers
2 communities served

Nebraska
291,700 utility customers
319 communities served

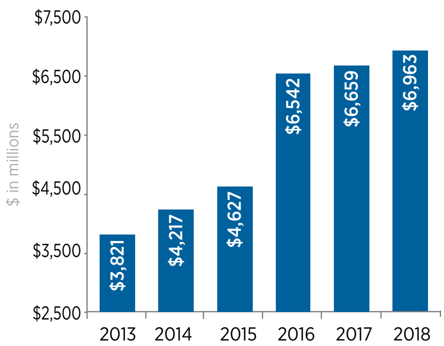
South Dakota
72,500 utility customers
29 communities served
130 megawatts of owned power generation capacity

Wyoming
172,800 utility customers
56 communities served
189 million tons of coal reserves
556 megawatts of owned power generation capacity

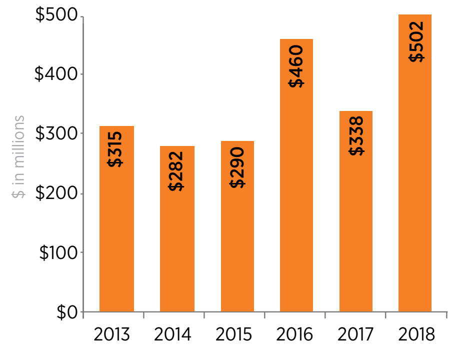


Total assets

2013-2018 CAGR 12.8%

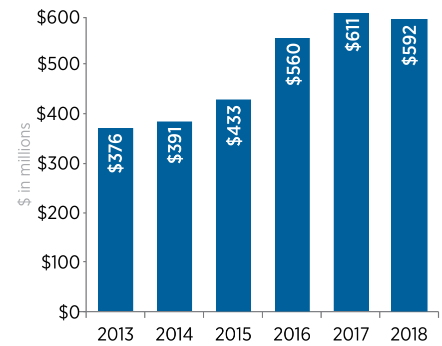


Capital expenditures[1]



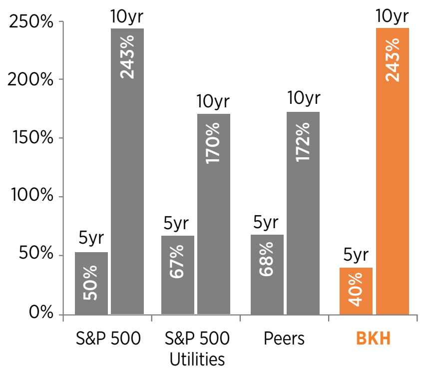
EBITDA, as adjusted[2]

2013-2018 CAGR 9.5%



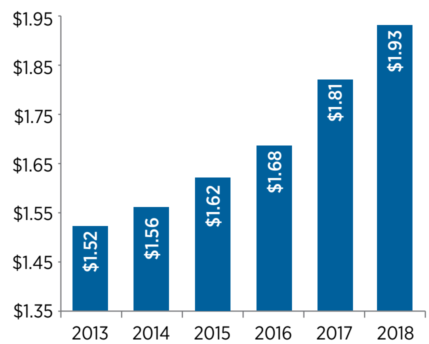
Total shareholder return

Data from S&P Global Market Intelligence



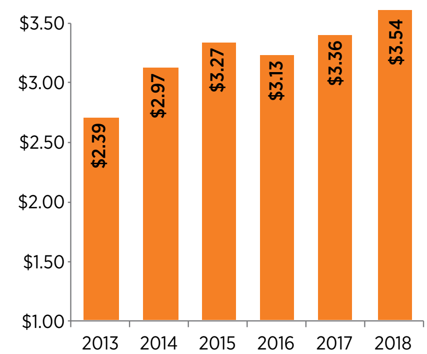
Dividend per share

2013-2018 CAGR 4.9%



Earnings per share, as adjusted[2,3]

2013-2018 CAGR 8.2%



(In millions except per share amounts)

STOCK INFORMATION (year-end)

	2018	2017	2016
Stock price	$62.78	$60.11	$61.34
Common shares outstanding	60.0	53.5	53.4
Market capitalization	$3,767	$3,218	$3,274

COMPANY KEY INDICATORS

	2018	2017	2016
Total capital expenditures[1]	$502	$ 338	$460
Total assets	$6,963	$6,659	$6,542
Total debt	$3,142	$3,326	$3,314
Net income available for common stock	$258	$177	$73

PER SHARE INFORMATION

	2018	2017	2016
Earnings per share: GAAP	$4.66	$3.21	$1.37
Earnings per share, as adjusted[2,3]	$3.54	$3.36	$3.13
Dividend per share	$1.93	$1.81	$1.68
Dividend yield: year-end	3.1%	3.0%	2.7%
Dividend growth	6.6%	7.7%	3.7%

1 From continuing operations; excludes capital for SourceGas purchase in 2016
2 Non-GAAP measure reconciled to GAAP starting on page A-1
3 From continuing operations
CAGR — Compound Annual Growth Rate

READY.

Dear Shareholders,

In 2018, Black Hills Corp. celebrated a milestone that is particularly meaningful for us — 135 years of providing essential energy to our customers — ensuring the strength and vitality of hundreds of towns and communities across our eight-state region through the safe and reliable delivery of electricity and natural gas.

Our tireless commitment to improving the lives of our customers is deeply grounded in our values and our proud legacy of service. It is with this in mind that we chose Ready as the theme of this report. With enthusiasm, confidence and determination, we are working to be "best in class" in everything we do — as an electric and natural gas utility company focused on serving our customers' energy needs today and well into the future. We are Ready.

We delivered strong results in 2018, providing outstanding value for you, our shareholders, and setting the foundation for our long-term success. With the divestiture of our oil and gas subsidiary now complete, we have intensified our utility focus to ensure the safety, reliability and integrity of our electric and natural gas systems while supporting customer growth and meeting changing customer expectations.


Linden "Linn" R. Evans
President and
Chief Executive Officer
David R. Emery
Executive Chairman
of the Board

DELIVERING STRONG FINANCIAL RESULTS

In 2018, we completed our transition to a more traditional utility growth strategy with a renewed customer emphasis. Our solid financial results for the year reflected ongoing investments to better serve our customers and support their increased demand for energy. For the year, we reported earnings per share from continuing operations, as adjusted, of $3.54, a 5.4 percent increase compared to 2017.[1] This was above our earnings expectations for the year, due in part to weather benefits, particularly in the fourth quarter.

We are driving long-term earnings growth by making essential capital investments to meet our customers' needs and by achieving operating efficiencies through business standardization. Our five-year capital investment program calls for the deployment of $2.5 billion to ensure the safety, reliability, and integrity of our extensive electric and natural gas systems — 9,000 miles of electric distribution and transmission lines and 46,000 miles of natural gas pipelines — while serving our expanding customer base. Incorporated in this investment on behalf of our customers is $128 million in new utility-scale renewable energy projects in Colorado and Wyoming to satisfy our customers' growing demand for renewable energy options and fulfill state requirements.

With our return to a more traditional utility growth strategy comes the need for more frequent regulatory rate reviews to ensure fair returns for shareholders on the considerable investments needed to better serve our customers. In 2018, our team successfully planned and executed a comprehensive regulatory strategy completing three rate reviews, including our first at Arkansas Gas since acquiring operations in the state in 2016. In addition, we submitted a long-term integrated electric resource plan in Wyoming, gained regulatory approval for a major pipeline project, and requested approval for a new wind generation project in Wyoming. And, to simplify regulatory and legal processes, we focused our efforts on consolidating multiple gas distribution utilities within Colorado, Wyoming and Nebraska. We continue to demonstrate our core strength in working through regulatory initiatives to achieve successful long-term results for all stakeholders.

1 Non-GAAP measure reconciled to GAAP starting on page A1

We celebrated our 135-year anniversary in 2018 by ringing the opening bell at the New York Stock Exchange. Black Hills Corp. has been a NYSE-listed company since July 1980, when it consisted of a single electric utility company with total assets of less than $150 million. Today, the company owns and operates 16 electric and natural gas utility businesses with total assets of more than $6.9 billion. We are proud of our proven ability to deliver outstanding long-term value to our shareholders.

Following the passage of the federal Tax Cuts and Jobs Act in late 2017, we acted quickly to ensure our customers received benefits of the new law. Over the course of 2018, we reached agreements with state regulators on the best way to return these benefits to customers. Our Wyoming implementation plan is the final state plan pending regulatory approval, which we expect during the first half of 2019.

As a demonstration of our confidence in our customer-focused growth strategy, we initiated earnings guidance for 2019 with a range of $3.35 to $3.55 per share, and initiated preliminary earnings guidance for 2020 with a range of $3.50 to $3.80 per share.

Despite a turbulent year for the stock market, our stock price increased by 4.4 percent to finish the year at $62.78 per share, while nearly all other market sectors finished in negative territory. We also strengthened the company's financial position during 2018 by finalizing the planned conversion of the equity units, issued in November 2015. Cash proceeds of nearly $300 million were used to pay down debt, which completed the financing related to the 2016 purchase of SourceGas.

Our improving balance sheet and the strategic exit of our oil and gas business continued to support our strong credit ratings. Black Hills received an upgrade from Standard and Poor's Global Ratings during the year with the other two major credit ratings agencies affirming our existing solid investment grade ratings. We are well-positioned to serve our customers with continued strong access to capital resources.

In 2018, we increased our annual dividend payout by 6.6 percent, to $1.93 per share, the 48th consecutive year of dividend increases, one of the longest track records in the utility industry. This signals our ongoing confidence in our strategic plan and future growth opportunities made possible, in part, by our successful acquisition and integration of SourceGas.

READY TO SERVE

Our dedicated team of nearly 2,900 individuals works with great intention and commitment to deliver the safe, reliable, and affordable energy our customers rely on each day to power their homes and businesses. It is our privilege to serve, ever mindful of delivering a superior experience in every customer interaction.

Our strategic utility acquisitions over the years continue to create long-term value for our customers, communities and shareholders. The resulting diversity of our eight-state service territory — spanning 1,600 miles across primarily rural towns and cities — reduces business risk and creates more predictable earnings.

Across every part of our service territory, from the back office to the front line, we are focused on providing our customers with the highest level of customer service. Placing our customers at the center of our business is an important part of our company's culture, so we work hard each day to ensure every employee understands their role in delivering value and benefit to our customers. With this in mind, we continue to improve our business practices to make it easier for our customers to do business with us.

Nebraska pipeline expansion project

DELIVERING VALUED SERVICE

ELECTRIC UTILITY HIGHLIGHTS

We operate electric utilities in Colorado, Montana, South Dakota and Wyoming, serving approximately 212,000 customers' energy needs with nearly 1 gigawatt of electric generation and a 9,000-mile electric transmission and distribution system. Black Hills produces energy using generation sources that balance reliability and affordability while being mindful of environmental impacts. To ensure our customers' energy needs are met today and well into the future, our generation portfolio includes clean, modern baseload coal plants and advanced, state-of-the-art natural gas-fired generating plants, along with an increasing emphasis on renewable energy resources, particularly wind and solar.

RELIABILITY PERFORMANCE AND LOAD GROWTH

In 2018, all three of our electric utilities achieved industry top quartile reliability performance for U.S. utilities — the 12th consecutive year — made possible by the outstanding performance of our generating plants and power delivery systems, especially during periods of high customer demand. Reflective of customer load growth in our service territory, our electric utilities in Colorado and Wyoming set new, all-time peak loads in 2018 in both summer and winter.

2018 PEAK SYSTEM DEMAND* (in megawatts)

Colorado	Summer	413**
	Winter	313**
Wyoming	Summer	254**
	Winter	238**
South Dakota	Summer	437
	Winter	379

* System Peak Demand represents the highest point of customer usage for a single hour for the system in total. Our system peaks include demand loads for 100% of plants regardless of joint ownership.

** New record for peak demand

ELECTRIC UTILITY HIGHLIGHTS CONTINUED

A STRONG, RESILIENT ENERGY GRID

To serve our customers and their growing energy needs, we have an imperative to maintain the safety, integrity and resiliency of our energy grid. Accordingly, we have comprehensive capital investment plans to replace aging infrastructure, modernize the grid, and expand our electric transmission and distribution systems across our diverse service territory. In 2018, we invested a total of $153 million across our three electric utilities to ensure the safe and reliable delivery of power to our customers, while enabling customer growth. One of our key projects to improve the safety and reliability of the grid has been our $70 million, 175-mile transmission line rebuild from Rapid City, South Dakota, to Stegall, Nebraska. In July, our South Dakota Electric utility placed in service the first 48-mile segment, with a second 33-mile segment placed in service in December. The remainder of the line is expected to be placed in service by the end of 2019.

Electrical engineers like Alyssa, regularly inspect the high voltage equipment needed to maintain our electric transmission and distribution system.

RENEWABLE READY

Cost-effective renewable energy is an increasingly important part of our balanced mix of generation resources. It represents a growing interest and expectation of our customers and stakeholders as well. Customer demand for renewable energy is on the rise, particularly among our large business customers, many of which have sustainability goals.

As a solution, we introduced a new, innovative tariff program in 2018 known as "Renewable Ready." As proposed, the Renewable Ready Service Tariff would provide large commercial and industrial customers and government agencies the option of purchasing utility-scale renewable energy resources through long-term subscriptions for up to 100 percent of participants' energy needs. Under proposals submitted in December, and now pending review by the South Dakota Public Utilities Commission and the Wyoming Public Service Commission, Renewable Ready would allow participants the ability to purchase renewable energy at a cost substantially lower than if they chose to install and maintain independent renewable energy systems on-site at their business locations.

Additionally, to establish a dedicated energy supply for the Renewable Ready program, we submitted a Certificate of Public Convenience and Necessity with Wyoming regulators in December to construct a new, 40 MW wind energy generating facility near Cheyenne — the Corriedale Wind Energy Project. If approved, the $57 million wind project is expected to be placed into service in the fall of 2020.

PLANNING FOR GROWTH, INVESTING IN OUR LOCAL COMMUNITIES

In December, our Wyoming Electric utility submitted its 2018 Integrated Resource Plan to the Wyoming Public Service Commission. This plan, now pending review by the Commission, outlines a comprehensive road map for acquiring the generation resources necessary to safely, reliably and affordably meet our customers' energy needs over the next 20 to 30 years. Our plan calls for a diverse mix of generation resources, building upon our modern generating fleet of low-emissions coal, natural gas and renewable energy as the preferred, least-cost options for serving customers' future energy needs.

In the near-term, the plan identified a baseload generation capacity shortfall of 60 MW — approximately 25 percent of the current capacity and energy needs for our Wyoming customers. This shortfall stems from the 2022 expiration of a power purchase agreement for energy produced at the Wygen I power plant, located near Gillette, which is owned by Black Hills Wyoming, an affiliate company.

Based on extensive planning and modeling, Wygen I is the best long-term solution to serve our customers' generation needs. The plant would ensure the price stability afforded by a low-cost, local Wyoming energy resource and continue to provide stable, long-term mining and plant operations jobs within Wyoming.

Over the longer-term, the resource plan supports the need for an additional 30 MW of energy capacity delivered from renewable energy resources.

POWER GENERATION HIGHLIGHTS

In Colorado, we have 89 MW of installed wind energy capacity at our Busch Ranch and Peak View wind facilities. We will add 60 MW of new wind capacity in 2019 with the construction of the $71 million Busch Ranch II wind farm, which was approved by the Colorado Public Utilities Commission in April. Following a competitive solicitation process, our non-regulated power generation subsidiary, Black Hills Electric Generation, was selected as the least-cost bidder for the new renewable energy resource. Our Colorado Electric utility will purchase 100 percent of the renewable energy generated at Busch Ranch II under a long-term, power purchase agreement. This additional renewable energy on our Southern Colorado system will achieve the policy objectives of Colorado's Renewable Energy Standard — a state mandate calling for 30 percent of customers' electricity consumption to come from renewable energy resources by 2020. We'll meet this requirement in late 2019. This renewable energy also supports the City of Pueblo's stated intention of providing its local citizens more energy from renewable generating resources.

In December, our power generation segment completed the $16 million purchase of a 50 percent ownership interest in the 29 MW Busch Ranch I wind farm located near Pueblo, Colorado. The energy generated at this facility is contracted to Colorado Electric through a power purchase agreement extending to 2037. Colorado Electric owns the remaining 50 percent interest and operates the entire wind farm.

Busch Ranch Wind Farm, Southern Colorado

NATURAL GAS UTILITY HIGHLIGHTS

Our natural gas utility operations serve nearly 1,054,000 customers in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming through 46,000 miles of transmission, distribution and service pipelines and natural gas storage fields. We are committed to ensuring the safe, reliable delivery of natural gas to our customers' homes and businesses and the communities we serve. To do so, we consistently invest in replacing, upgrading and maintaining our critical infrastructure.

READY TO MEET OUR CUSTOMERS' NEEDS

In Arkansas, we completed a rate review in 2018 to recover more than $160 million in investments to install, replace, upgrade and maintain more than 6,800 miles of natural gas pipeline. These investments have facilitated economic growth while improving safety and reliability and meeting compliance requirements of state and federal regulations. In October, the Arkansas Public Service Commission approved a general rate increase of $12 million in new annual revenue to recover these critical investments.

In November, we received approval from the Wyoming Public Service Commission for a Certificate of Public Convenience and Necessity to construct a new $54 million, 35-mile natural gas pipeline to enhance supply reliability and delivery capacity for approximately 57,000 customers in central Wyoming. Known as the Natural Bridge Pipeline, this project continues our long-term effort to enhance reliability across our natural gas pipeline system and better ensures our ability to cost-effectively meet our customers' long-term needs. The pipeline is planned to be in service in late 2019.

IMPROVING THE CUSTOMER EXPERIENCE

To effectively serve our customers, we commenced a multi-year effort to simplify regulatory and legal processes. We started in 2018 by consolidating our two gas distribution utility businesses in Colorado into a single new company called Black Hills Colorado Gas. We followed up with a proposal in early 2019 seeking approval from the Colorado Public Utilities Commission to streamline the rates, tariffs and services of those existing Colorado gas territories. In the request, we also seek to recover $44 million invested in 2018 on maintenance, replacements and upgrades within our Colorado Gas system — critical infrastructure needed to ensure the safe and reliable delivery of natural gas to our 187,000 customers. The proposal is now pending review with a decision expected in mid-2019.

We will continue the process of jurisdiction simplification of our gas distribution utility businesses with filings in Wyoming and Nebraska in 2019.

NATURAL GAS UTILITY HIGHLIGHTS CONTINUED

PROGRAMMATIC SYSTEM INVESTMENTS

To better serve our customers and improve the safety, reliability and integrity of our natural gas system, we are proactively replacing aging infrastructure. By taking a programmatic approach, we are methodically planning pipeline maintenance and replacement to mitigate risk and prioritize the deployment of resources and capital across our extensive natural gas system. This has led to an accelerated capital investment program, supported by our state regulatory commissions through an increase and/or extension of system safety and integrity riders as highlighted below:

- In June, Kansas Gas received approval from the Kansas Corporation Commission to double eligible system integrity and safety investments from $8 million per year to $16 million per year.
- In July, Rocky Mountain Natural Gas, an intrastate pipeline company in Colorado, extended its system safety and integrity rider to recover investments from 2018 through 2021. This extension is part of a settlement agreement of a rate review filed in Oct. 2017.
- Also in July, Wyoming Gas received approval for new rates to recover approximately $6 million of system integrity investments.
- In September, Nebraska Gas Distribution received approval from the Nebraska Public Service Commission to extend the recovery period of its system safety and integrity rider from Oct. 31, 2019 to Dec. 31, 2020, continuing approximately $6 million of revenue annually.

Fayetteville engineers, Logan and Cole, design improvements to our Arkansas natural gas transmission system.

LIVING OUR VALUES

At Black Hills Energy, we believe we all have a hand in making our company a great place to work. This starts with placing safety at the forefront of all we do. Our daily work practices, policies and programs are aimed at creating a safer and healthier environment for our employees. Because of this dedication and focus, we have reduced workplace injuries by more than 74 percent over the past 11 years.

From boots on the ground to safety in the office, every meeting and every job starts with a safety share or a safety tailboard. In the field, potential hazards are discussed before the job begins and necessary precautions are taken to protect employees and our communities. We are committed to being the safest utility company in the nation and this requires persistent, daily attention in all we do.

In 2018, our Total Case Incident Rate (incidents per 200,000 hours worked) was 1.2, compared to 1.3 in 2017 and well below the utility industry average of 2.2. Our preventable motor vehicle incident rate (vehicle accidents per 1 million miles driven), another indicator of our safety performance, was 2.2 in 2018, a slight increase over 2.0 in 2017, but below the industry average of 2.3.

In addition to these key safety metrics, we are two years into an initiative to promote overall employee health and wellness with participation levels at more than 90 percent.

Creating a culture of inclusion is another area of focus for us, and it starts with a commitment at the highest levels of leadership to ensure all employees are valued and respected at Black Hills. This "tone from the top" starts with building a bench of leaders that reflect diverse backgrounds and perspectives. In 2018, 38 percent of our leadership team was diverse in terms of gender and ethnicity. We are continuing to add outreach programs, community partnerships and leadership development programs that foster a culture of growth and belonging at all levels within our company.

We've put a lot of effort into being a great workplace for our employees and our progress is being recognized. In 2018, Forbes Magazine named Black Hills Energy to its America's Best Midsize Employers list, the second year we've been honored. We're extremely proud to be ranked as one of the best midsize employers in the country — 187th out of 500 selected for this prestigious list.

Agility | Communication | Creating Value | Customer Service | Integrity | Leadership | Partnership | Respect | Safety

TRANSITION OF LEADERSHIP

After more than 29 incredibly rewarding years with Black Hills Corp., including 15 years as CEO, with 14 of those as Chairman, I retired as CEO effective Dec. 31, 2018. To help ensure a smooth transition, I will continue to serve as an employee of the company in the role of Executive Chairman of the Board until May 1, 2020, through the end of my current Board term, which ends at the April 2020 annual meeting of shareholders. Consistent with the company's long-standing, comprehensive organization and leadership review process, the Board appointed Linn Evans, President and Chief Operating Officer, to succeed me as CEO effective Jan. 1, 2019. Linn was also appointed to the Board of Directors effective Nov. 1, 2018.

It has been my great privilege and the highlight of my career to serve and lead the best employee team in the industry during a period of great transformation and growth. As a result of the combined effort of our entire employee team over the past 15 years, the company tripled its assets from $2.1 billion to $6.9 billion, increased market capitalization from $900 million to nearly $4 billion, grew our customer base from 61,000 to 1.27 million, and expanded our employee team from fewer than 900 to nearly 2,900 today. Linn played a key leadership role throughout this period of historic change and I am confident he is the right person to lead Black Hills into the future. I look forward to assisting Linn and the leadership team in my new role.

With gratitude — Dave Emery

Linn Evans and Dave Emery

IMPROVING LIFE WITH ENERGY

Each day, Black Hills Improves Life with Energy by providing essential energy to our customers and communities. This goes well beyond the safe delivery of electricity and natural gas. It encompasses the energy of our entire Black Hills team and our commitment to improving the communities in which we live and work. In 2018, our community support totaled over $4.1 million, including nearly $500,000 in employee giving to United Way agencies and affiliates across our service territory. Our employees and their families also give generously of their time — thousands of hours each year — engaging in volunteer service projects in cities and towns across each of our states. Giving back is a value we hold dear and another way of showing we are Ready to serve.

We had a successful and productive year in 2018 and we are extremely proud of the performance of our team as we worked together, tightly aligned, to execute our strategy. We are well-positioned and Ready to continue along this path, delivering value for our customers and shareholders for years to come.

Thank you for the confidence and trust you have placed in our company. We look forward to another outstanding year in 2019.

Sincerely,

David R. Emery and Linden "Linn" R. Evans

Lineworkers like Ben, maintain the safety and reliability of our electric distribution system.

PROXY STATEMENT

BLACK HILLS CORPORATION

Notice of 2019
Annual Meeting of Shareholders
and Proxy Statement

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BLACK HILLS CORPORATION

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

WHEN:

Tuesday, April 30, 2019
9:30 a.m., local time

WHERE:

Horizon Point
Company's Corporate Headquarters
7001 Mount Rushmore Road
Rapid City, South Dakota 57702

We are pleased to invite you to attend the annual meeting of shareholders of Black Hills Corporation.

Proposals:

1. Election of three directors in Class I: Robert P. Otto, Mark A. Schober and Thomas J. Zeller; and one director in Class III: Linden R. Evans.
2. Ratification of Deloitte & Touche LLP to serve as our independent registered public accounting firm for 2019.
3. Adoption of an advisory, non-binding resolution to approve our executive compensation.
4. Any other business that properly comes before the annual meeting.

Record Date:

The Board of Directors set March 1, 2019 as the record date for the meeting. This means that our shareholders as of the close of business on that date are entitled to receive this notice of the meeting and vote at the meeting and any adjournments or postponements of the meeting.

How to Vote:

Your vote is very important. You may vote your shares by telephone, by the Internet or by returning the enclosed proxy. If you own shares of common stock other than the shares shown on the enclosed proxy, you will receive a proxy in a separate envelope for each such holding. Please vote each proxy received. To make sure that your vote is counted if voting by mail, you should allow enough time for the postal service to deliver your proxy before the meeting.

Sincerely,

BRIAN G. IVERSON
Senior Vice President, General Counsel and Corporate Secretary

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BLACK HILLS CORPORATION

7001 Mount Rushmore Road
Rapid City, South Dakota 57702

PROXY STATEMENT

✓ A proxy in the accompanying form is solicited by the Board of Directors of Black Hills Corporation, a South Dakota corporation, to be voted at the annual meeting of our shareholders to be held Tuesday, April 30, 2019, and at any adjournment of the annual meeting.

✓ The enclosed form of proxy, when executed and returned, will be voted as set forth in the proxy. Any shareholder signing a proxy has the power to revoke the proxy in writing, addressed to our secretary, or in person at the meeting at any time before the proxy is exercised.

✓ We will bear all costs of the solicitation. In addition to solicitation by mail, our officers and employees may solicit proxies by telephone, fax, or in person. We have retained Georgeson LLC to assist us in the solicitation of proxies at an anticipated cost of $8,000, plus out-of-pocket expenses. Also, we will, upon request, reimburse brokers or other persons holding stock in their names or in the names of their nominees for reasonable expenses in forwarding proxies and proxy materials to the beneficial owners of stock.

✓ This proxy statement and the accompanying form of proxy are to be first mailed on or about March 15, 2019. Our 2018 annual report to shareholders is being mailed to shareholders with this proxy statement.

VOTING RIGHTS AND PRINCIPAL HOLDERS

✓ Only our shareholders of record at the close of business on March 1, 2019 are entitled to vote at the meeting. Our outstanding voting stock as of the record date consisted of ________________shares of our common stock.

✓ Each outstanding share of our common stock is entitled to one vote. Cumulative voting is permitted in the election of directors in the same class.

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COMMONLY ASKED QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING PROCESS

Who is soliciting my proxy?

The Board of Directors of Black Hills Corporation is soliciting your proxy.

Where and when is the annual meeting?

The annual meeting is at 9:30 a.m., local time, April 30, 2019 at Horizon Point, the Company's corporate headquarters, 7001 Mount Rushmore Road, Rapid City, South Dakota.

Who can vote?

Holders of our common stock as of the close of business on the record date, March 1, 2019, can vote at our annual meeting. Each share of our common stock has one vote for Proposals 2 and 3. Related to Proposal 1, Election of Directors, cumulative voting is permitted in the election of directors in the same class.

How do I vote?

There are three ways to vote by proxy:

- by calling the toll free telephone number on the enclosed proxy;
- by using the Internet by going to the website identified on the enclosed proxy; or
- by returning the enclosed proxy in the envelope provided.

You *may* be able to vote by telephone or the Internet if your shares are held in the name of a bank or broker. If this is the case, you will need to follow their instructions.

What constitutes a quorum?

Shareholders representing at least 50 percent of our common stock issued and outstanding as of the record date must be present at the annual meeting, either in person or by proxy, for there to be a quorum. Abstentions and broker non-votes are counted as present for establishing a quorum. A broker non-vote occurs when a broker or other nominee holding shares for a beneficial owner does not vote on a particular proposal because the broker or nominee does not have discretionary voting power and has not received instructions from the beneficial owner.

What am I voting on and what is the required vote for the proposals to be adopted?

The required vote and method of counting votes for the various business matters to be considered at the annual meeting are described in the table below. If you sign and return your proxy card without indicating your vote, your shares will be voted in accordance with the Board recommendations as set forth below.

Item of Business	Board Recommendation	Voting Approval Standard	Effect of Abstention	Effect of Broker Non-Vote
Proposal 1: Election of Directors	FOR election of each director nominee	The four nominees with the most "FOR" votes are elected. If a nominee receives more "WITHHOLD AUTHORITY" votes than "FOR" votes, the nominee must submit a resignation for consideration by the Governance Committee and final Board decision.	No effect	No effect
Proposal 2: Ratification of Appointment of Independent Registered Public Accounting Firm	FOR	The majority of votes present in person or represented by proxy and entitled to vote.	No effect	Not applicable; broker may vote shares without instruction
Proposal 3: Advisory Vote to Approve Executive Compensation	FOR	The majority of votes present in person or represented by proxy and entitled to vote. This advisory vote is not binding on the Board, but the Board will consider the vote results when making future executive compensation decisions.	No effect	No effect

Is cumulative voting permitted for the election of directors?

In the election of directors, you may cumulate your vote. Cumulative voting allows you to allocate among the director nominees in the same class, as you see fit, the total number of votes equal to the number of director positions to be filled multiplied by the number of shares you hold. For example, if you own 100 shares of stock, and there are three directors to be elected at the annual meeting, you could allocate 300 “For” votes (three times 100) among as few or as many of the three nominees to be voted on at the annual meeting as you choose.

If you choose to cumulate your votes, you will need to submit a proxy card or a ballot and make an explicit statement of your intent to cumulate your votes, either by indicating in writing on the proxy card or by indicating in writing on your ballot when voting at the annual meeting. If you hold shares beneficially in street name and wish to cumulate votes, you should contact your broker, trustee or nominee.

How will my shares be voted if they are held in a broker’s name?

If you hold your shares through an account with a bank or broker, the bank or broker may vote your shares on some matters even if you do not provide voting instructions. Brokerage firms have the authority under the New York Stock Exchange ("NYSE") rules to vote shares on certain matters (such as the ratification of auditors) when their customers do not provide voting instructions. However, on most other matters when the brokerage firm has not received voting instructions from its customers, the brokerage firm cannot vote the shares on that matter and a “broker non-vote” occurs. **This means that brokers may not vote your shares on the election of directors or on the “say on pay” advisory vote if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so that your vote can be counted.**

What should I do now?

You should vote your shares by telephone, by the Internet or by returning your signed and dated proxy card in the enclosed envelope as soon as possible so that your shares will be represented at the annual meeting.

Who will count the vote?

Representatives of our transfer agent, Equiniti Trust Company (previously Wells Fargo Bank, N.A.), will count the votes and serve as judges of the election.

Who conducts the proxy solicitation and how much will it cost?

We are asking for your proxy for the annual meeting and will pay all the costs of asking for shareholder proxies. We have hired Georgeson LLC to help us send out the proxy materials and ask for proxies. Georgeson LLC's fee for these services is anticipated to be $8,000 plus out-of-pocket expenses. We can ask for proxies through the mail or by telephone, fax, or in person. We can use our directors, officers and employees to ask for proxies. These people do not receive additional compensation for these services. We will reimburse brokers and other custodians, nominees and fiduciaries for their reasonable out-of-pocket expenses for forwarding solicitation material to the beneficial owners of our common stock.

Can I revoke my proxy?

Yes. You can change your vote in one of four ways at any time before your proxy is used. First, you can enter a new vote by telephone or Internet. Second, you can revoke your proxy by written notice. Third, you can send a later dated proxy changing your vote. Fourth, you can attend the meeting and vote in person.

Who should I call with questions?

If you have questions about the annual meeting, you should call Brian G. Iverson, Senior Vice President, General Counsel, and Corporate Secretary at (605) 721-1700.

When are the shareholder proposals due for the 2020 annual meeting?

In order to be considered for inclusion in our proxy materials, you must submit proposals for next year's annual meeting in writing to our Corporate Secretary at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to November 16, 2019.

A shareholder who intends to submit a proposal for consideration, but not for inclusion in our proxy materials, must provide written notice to our Corporate Secretary in accordance with Article I, Section 9 of our Bylaws. In general, our Bylaws provide that the written notice must be delivered not less than 90 days nor more than 120 days prior to the first anniversary date of the immediately preceding annual meeting of shareholders. Our 2019 annual meeting is scheduled for April 30, 2019. Ninety days prior to the first anniversary of this date will be January 31, 2020, and 120 days prior to the first anniversary of this date will be January 1, 2020.

PROPOSAL 1	ELECTION OF DIRECTORS

Our Board is nominating four individuals for election as directors at this annual meeting. All of the nominees are currently serving as our directors. In accordance with our Bylaws and Article VI of our Articles of Incorporation, members of our Board of Directors are elected to three classes of staggered terms consisting of three years each, and until their successors are duly elected and qualified. At this annual meeting, three directors will be elected to Class I for a term of three years until our annual meeting in 2022, and one director will be elected to Class III to complete the remainder of the term expiring at our annual meeting in 2021.

Nominees for director at the annual meeting are Linden R. Evans, Robert P. Otto, Mark A. Schober and Thomas J. Zeller. Our Bylaws require a minimum of nine directors. The Board has set the size of the current board at 10 directors. If, at the time of the meeting, any of such nominees are unable to stand for election, the Board of Directors may designate a substitute or reduce the number of directors to nine. In that case, shares represented by proxies may be voted for a substitute director. We do not expect that any nominee will be unavailable or unable to serve.

Pursuant to our Bylaws, directors must resign from the Board at the annual meeting following attaining 72 years of age. Accordingly, we expect Mr. Zeller, who will turn 72 in the next year, to resign effective at our annual meeting in 2020 and therefore serve only one year of his term.

The Board and the Governance Committee believe that the combination of the various qualifications, skills and experiences of the directors contribute to an effective and well-functioning Board, and that, individually and as a whole, the directors possess the necessary qualifications to provide effective oversight of the business and quality advice to the Company’s management. Included in each director’s biography below is an assessment of the specific qualifications, attributes, skills and experience that have led to the conclusion that each individual should serve as a director in light of our current business and structure.

The Board of Directors recommends a vote *FOR* the election of the following nominees:

Director Nominee	Class	Year Term Expiring
Linden R. Evans	III	2021
Robert P. Otto	I	2022
Mark A. Schober	I	2022
Thomas J. Zeller	I	2022

DIRECTOR BIOGRAPHIES

Average Tenure	Average Age	Diversity
8 Years	63	20% Women 10% Ethnic

David R. Emery	Executive Chairman of the Company's Board of Directors since January 1, 2019. Chairman and Chief Executive Officer from 2016 through 2018. Chairman, President and Chief Executive Officer from 2005 through 2015.
Director since 2004 **Director** Class II Term Expiring 2020 **Age** 56 **Board Committees** None **Other Public Company Boards** None **Ethnic Diversity** Enrolled member of Cheyenne River Sioux Tribe	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **High Level of Financial Expertise** Oversaw financial matters in his role as Chairman of the Board and Chief Executive Officer of the Company. Led the Company through several successful acquisitions and divestitures. Served as Interim Chief Financial Officer in 2008. **Relevant Senior Leadership Experience** Currently Executive Chairman of the Company's Board of Directors. Previously served in various leadership roles with the Company, including Chairman and Chief Executive Officer, Chairman, President and Chief Executive Officer, President and Chief Operating Officer - Retail Business Segment and Vice President - Fuel Resources. Serves on the Board of Directors and Audit Committee of the Federal Reserve Bank of Minneapolis. **Extensive Knowledge of the Company’s Business and/or Industry** 29 years of experience with the Company, including 15 years on the Board. Prior to joining the Company, he served as a petroleum engineer for a large independent oil and gas company. Serves on many industry association boards and advisory committees.

Linden R. Evans	President and Chief Executive Officer of the Company since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer - Utilities from 2004 through 2015.
Director since November 2018 **Director Nominee** Class III Term Expiring 2021 **Age** 56 **Board Committees** None **Other Public Company Boards** None	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **Broad Range of Experience** Broad range of experience in his career in areas of utility management, strategic planning and execution, telecommunications, corporate legal and environmental matters. **Relevant Senior Leadership Experience** Currently President and Chief Executive Officer of the Company. Previously served in various leadership roles with the Company. **Extensive Knowledge of the Company's Business and/or Industry** 17 years of experience with the Company. Prior to joining the Company, he was a mining engineer and an attorney specializing in environmental and corporate legal matters. Member of many industry associations.

Michael H. Madison	Retired. Former President and Chief Executive Officer and Director of Cleco Corporation, a public utility holding company, from 2005 to 2011.
Director since 2012 **Director** Class III Term Expiring 2021 **Age** 70 **Board Committees** Compensation (Chair) Governance **Other Public Company Boards** None	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **High Level of Financial Expertise** Oversaw financial matters in his role as Chief Executive Officer and Director of a public company. Previously served on our Audit Committee. **Relevant Senior Leadership Experience** Served as Chief Executive Officer and Director of Cleco Corporation from 2005 to 2011, and President and Chief Operating Officer of Cleco Power, LLC from 2003 to 2005. He was State President, Louisiana-Arkansas with American Electric Power from 2000 to 2003. **Extensive Knowledge of the Company’s Business and/or Industry** More than 40 years of utility industry experience in various positions of increasing responsibility, including president, director, vice president of operations, engineering and production and vice president of corporate services. Served on many industry association boards and advisory committees.

Steven R. Mills	Financial Consultant and Advisor to clients in the private equity, agribusiness, renewable products and financial services fields, since 2013. Served as Chief Financial Officer of Amyris, Inc., an integrated renewable products company, from 2012 to 2013. Also served as Senior Executive Vice President Performance and Growth of Archer Daniels Midland Company, a processor, transporter, buyer and marketer of agricultural products, from 2010 to 2012.
Director since 2011 **Director** Class III Term Expiring 2021 **Age** 63 **Board Committees** Audit (Chair) **Other Public Company Boards** Amyris, Inc. (since 2018)	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **High Level of Financial Expertise** Oversaw financial matters in his role as Chief Financial Officer at public companies. More than 35 years of experience in the fields of accounting, corporate finance, strategic planning, and mergers and acquisitions. Served on our Audit Committee for 8 years, including the past 4 years as Audit Chair. **Relevant Senior Leadership Experience** Served in several leadership positions with public companies including, Chief Financial Officer, Senior Executive Vice President Performance and Growth and Senior Vice President Strategic Planning. He has also served as a director and board committee chair of several public and privately-owned companies, providing governance and oversight experience. **Risk Oversight/Management Expertise** Significant risk oversight/management experience throughout his career in various executive leadership, finance and business consulting positions, including Chief Financial Officer at public companies.

Robert P. Otto	Owner of Bob Otto Consulting LLC, providing strategic planning and services in cyber security, intelligence, and reconnaissance since 2017. He retired from the U.S. Air Force in 2016 as a lieutenant general. He served as a general officer since 2008, culminating as the Air Force Deputy Chief of Staff for Intelligence, Surveillance and Reconnaissance.
Director since 2017 **Director Nominee** Class I Term Expiring 2022 **Age** 59 **Board Committees** Audit **Other Public Company Boards** None	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **Financially Literate** Vast experience in areas spanning cyber security, strategic planning, and financial management from his military career. Serves on our Audit Committee. **Relevant Senior Leadership Experience** Commanded some of the Air Force's largest organizations with thousands of employees and billion-dollar budgets. Intelligence and cyber security expert with a proven record of success executing cost-effective, cutting-edge initiatives. Extensive background in operations, financial management, policy development, restructuring, and systems implementation. **Risk Oversight/Management Expertise** Significant risk oversight/management experience throughout his military career. As the Air Force's senior-most intelligence officer, he was directly responsible for policy planning, evaluation, oversight and leadership of Air Force intelligence, surveillance and reconnaissance capabilities.

Rebecca B. Roberts	Retired. Former President of Chevron Pipe Line Company, a pipeline company transporting crude oil, refined petroleum products, liquefied petroleum gas, natural gas and chemicals within the United States, from 2006 to 2011. President of Chevron Global Power Generation from 2003 to 2006.
Director since 2011 **Director** Class II Term Expiring 2020 **Age** 66 **Board Committees** Compensation Governance (Chair) **Other Public Company Boards** AbbVie, Inc. (since 2018) MSA Safety, Inc. (since 2013) **Gender Diversity**	**<u>Specific Qualifications, Attributes, Skills and Experience:</u>** **Financially Literate** Operational and financial experience as a president of large public company subsidiaries and serving on public company boards. **Relevant Senior Leadership Experience** Served as President of Chevron Pipe Line Company from 2006 to 2011, and President of Chevron Global Power Generation from 2003 to 2006. She has also served on several public company and non-profit boards in addition to the ones identified at the left, including the board of Enbridge, Inc., from 2015 through May 2018. **Extensive Knowledge of the Company's Business and/or Industry** Over 35 years of experience in the energy industry, including managing pipelines in North America and global pipeline projects, and managing a portfolio of power plants in the United States, Asia and the Middle East. She also worked as a vice president, chemist, scientist and trader in the oil and gas sectors.

Mark A. Schober	Retired. Former Senior Vice President and Chief Financial Officer of ALLETE, Inc., a public energy company, from 2006 to 2014.
Director since 2015 **Director Nominee** Class I Term Expiring 2022 **Age** 63 **Board Committees** Audit **Other Public Company Boards** None	**Specific Qualifications, Attributes, Skills and Experience:** **High Level of Financial Expertise** Oversaw financial matters in his role as Chief Financial Officer of a public utility company. More than 35 years of experience in the fields of finance and accounting. Serves on our Audit Committee. **Relevant Senior Leadership Experience** Served as Chief Financial Officer of ALLETE, Inc., a public utility company, from 2006 to 2014. **Extensive Knowledge of the Company's Business and/or Industry** More than 35 years of experience in the utility and energy industry, including an understanding of the regulated business model and unique challenges of the geographic and regulatory environment in which we operate.

Teresa A. Taylor	Chief Executive Officer of Blue Valley Advisors, LLC, an advisory firm, since 2011. Former Chief Operating Officer of Qwest Communications, Inc., a telecommunications carrier, from 2009 to 2011.
Director since 2016 **Director** Class II Term Expiring 2020 **Age** 55 **Board Committees** Compensation **Other Public Company Boards** T-Mobile USA, Inc. (since 2013) First Interstate BancSystem, Inc. (since 2012) **Gender Diversity**	**Specific Qualifications, Attributes, Skills and Experience:** **Broad Range of Experience** Gained a broad range of experience in her career in areas of strategic planning and execution, technology development, human resources, labor relations and corporate communications. **Relevant Senior Leadership Experience** Served as Chief Operating Officer of Qwest Communications, Inc. where she led the daily operations and a senior management team responsible for 30,000 employees in field support, technical development, sales, marketing, customer support and IT systems. She has also served on several public company and non-profit boards in addition to the ones identified at the left. **Extensive Knowledge of the Company's Business and/or Industry** Over 30 years of experience in technology, media and the telecom sector. Served on the Board of NiSource, a public utility company, from 2012 to 2015 and Columbia Pipeline Group, Inc. from 2015 to July 2016.

John B. Vering	Managing Director of Lone Mountain Investments, Inc., oil and gas investments, since 2002. Partner in Vering Feed Yards LLC, a privately owned agricultural company, since 2010.
Director since 2005 **Director** Class II Term Expiring 2020 **Age** 69 **Board Committees** Lead Director Audit Governance **Other Public Company Boards** None	**Specific Qualifications, Attributes, Skills and Experience:** **High Level of Financial Expertise** Has gained a high level of financial expertise as Managing Director of an entity making oil and gas investments. Has served on our Audit Committee for 9 years. **Relevant Senior Leadership Experience** Serves as our Lead Director. Had a 23-year career with Union Pacific Resources Company in several positions of increasing responsibilities, including Vice President of Canadian Operations. **Extensive Knowledge of the Company's Business and/or Industry** Over 30 years of experience in the oil and gas industry, including direct operating experience in oil and gas transportation, marketing, exploration and production, and an understanding of the trans-national oil and gas business. He has served on our Board for 14 years and as our Lead Director since March 2016.

Thomas J. Zeller	Retired. Former Chief Executive Officer of RESPEC, a technical consulting and services firm with expertise in engineering, information technologies, and water and natural resources specializing in emerging environmental protection protocols, in 2011 and served as President from 1995 to 2011.
Director since 1997 **Director Nominee** Class I Term Expiring 2022 **Age** 71 **Board Committees** Compensation Governance **Other Public Company Boards** None	**Specific Qualifications, Attributes, Skills and Experience:** **High Level of Financial Expertise** Oversaw financial matters in his roles as Chief Executive Officer, President and Vice President of Finance for a large technical consulting and services firm. He served on our Audit Committee for 11 years, including serving as the Audit Committee Chair for 4 years. **Relevant Senior Leadership Experience** Previously served as our Lead Director from 2010 to February 2016. Executive leader at a global technical consulting firm. He has served on several non-profit boards. **Extensive Knowledge of the Company's Business and/or Industry** Experience gained at RESPEC relates to many of our Company's activities concerning technology, engineering and environmental. With his long tenure on our Board, he has developed an extensive knowledge of the utility industry.

CORPORATE GOVERNANCE

Corporate Governance Guidelines

Our Board of Directors has adopted corporate governance guidelines titled “Corporate Governance Guidelines of the Board of Directors,” which guide the operation of our Board and assist the Board in fulfilling its obligations to shareholders and other constituencies. The guidelines lay the foundation for the Board’s responsibilities, operations, leadership, organization and committee matters. The Governance Committee reviews the guidelines annually, and the guidelines may be amended at any time, upon recommendation by the Governance Committee and approval of the Board. These guidelines can be found in the “Governance” section of our website (www.blackhillscorp.com/investor-relations/corporate-governance).

Board Independence

In accordance with NYSE rules, the Board of Directors through its Governance Committee affirmatively determines the independence of each director and director nominee in accordance with guidelines it has adopted, which include all elements of independence set forth in the NYSE listing standards. These guidelines are contained in our Policy for Director Independence, which can be found in the “Governance” section of our website (www.blackhillscorp.com/investor-relations/corporate-governance). Based on these standards, the Governance Committee determined that each of the following non-employee directors is independent and has no relationship with us, except as a director and shareholder:

Michael H. Madison	80% INDEPENDENT	Mark A. Schober
Steven R. Mills		Teresa A. Taylor
Robert P. Otto		John B. Vering
Rebecca B. Roberts		Thomas J. Zeller

In addition, based on such standards, the Governance Committee determined that Messers. Emery and Evans are not independent because they are Officers of the Company.

Board Leadership Structure

As part of a planned leadership transition, Mr. Emery, after 14 years as Chairman and CEO, was appointed Executive Chairman of the Board of Directors. Mr. Evans, who has been President and Chief Operating Officer since 2016, was named President and CEO effective January 1, 2019. To ensure a seamless transition of our CEO role, Mr. Emery collaborates closely with our new CEO on corporate strategy and other items.

Our Board has and continues to value a high degree of Board independence. As a result, our corporate governance structure and practices promote a strong, independent Board and include several independent oversight mechanisms. Only independent directors serve on our Audit, Compensation and Governance Committees. Our Board believes these practices ensure that experienced and independent directors will continue to effectively oversee management and critical issues related to financial and operating plans, long-range strategic issues, enterprise risk and corporate integrity. All of our Board committees may seek legal, financial or other expert advice from a source independent of management.

As provided in our Corporate Governance Guidelines of the Board of Directors, because our Executive Chairman is not independent, our Board annually appoints an independent Lead Director. John B. Vering is our current Lead Director and has served in this role since March 2016. As provided in the Corporate Governance Guidelines, the primary responsibilities of the Lead Director are to chair executive sessions of the independent directors, and in conjunction with the Executive Chairman, communicate the Board’s annual evaluation of the CEO. The Lead Director, together with the independent directors, establishes the agenda for executive sessions, which are held at each regular Board meeting. The Lead Director serves as a liaison between the independent members of the Board, the Executive Chairman, and the CEO, as appropriate, and discusses, to the extent appropriate, matters raised by the independent directors in executive session. The Lead Director also consults with the Executive Chairman, and the CEO, as appropriate, regarding meeting agendas and presides over regular meetings of the Board in the absence of the Executive Chairman. This leadership structure provides consistent and effective oversight of our management and our Company.

Risk Oversight

Our Board oversees an enterprise approach to risk management that supports our operational and strategic objectives. The Corporate Governance Guidelines of the Board of Directors provide that the Board will review major risks facing our Company and the options for risk mitigation presented by management. Our Board delegates oversight of certain risk considerations to its committees within each of their respective areas of responsibility; however, the full Board monitors risk relating to strategic planning and execution, as well as executive succession. Financial risk oversight falls within the purview of our Audit Committee. Our Compensation Committee oversees compensation and benefit plan risks. Each committee reports to the full Board.

Our Board reviews any material changes in our key enterprise risk management ("ERM") issues, including cyber security, with management at each quarterly Board meeting. In addition, the Board reviews a deep dive enterprise risk topic with our Chief Risk Officer at most quarterly meetings. In so doing, our Board seeks to ensure appropriate risk mitigation strategies are implemented by management on an ongoing basis. Operational and strategic plan presentations by management to our Board include consideration of the challenges and risks to our business. Our Board and management actively engage in discussions of these topics and utilize outside consultants as needed. Our Board oversees the assessment of our strategic plan risks as part of our strategic planning process. In addition, our Board periodically receives safety performance, operations, environmental, legal and compliance reports.

Our Audit Committee oversees management's strategy and performance relative to our significant financial risks. In consultation with management, the independent auditors and the internal auditors, the Audit Committee discusses our risk assessment, risk management and credit policies and reviews significant financial risk exposures, along with steps management has taken to monitor, mitigate and report such exposures. At least twice a year, our Chief Risk Officer provides a Risk Report and the Treasurer provides a Credit Report to the Audit Committee. We adopted a Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within established risk tolerances.

Our Compensation Committee adopted an executive compensation philosophy that provides the foundation for our executive compensation program. The executive compensation philosophy states that the executive pay program should be market-based and maintain an appropriate and competitive balance between fixed and variable pay elements, short-term and long-term compensation and cash and stock-based compensation. The Compensation Committee establishes company-specific performance goals with potential incentive payouts for our executive officers to motivate and reward performance, consistent with our long-term success. The target compensation for our senior officers is weighted in favor of long-term incentives, aligning performance incentives with long-term results for our shareholders. Our Compensation Committee also sets minimum performance thresholds and maximum payouts in the incentive programs and maintains the discretion to reduce awards if excessive risk is taken. Stock ownership guidelines established for all of our officers require our executives to hold 100 percent of all shares awarded to them (net of share withholding for taxes and, in the case of cashless stock option exercises, net of the exercise price and withholding for taxes) until the established stock ownership guidelines are achieved. Our Compensation Committee also includes "clawback" provisions in our incentive plans, which may require an executive to return incentives received, if the Compensation Committee determines, in its discretion, that the executive engaged in specified misconduct or wrongdoing or in the event of certain financial restatements.

In addition, management periodically conducts and our Compensation Committee reviews a risk assessment of the Company's compensation policies and practices for all employees. This was last done in December 2017 and there have been no material changes in our policies and practices since that time. Key members of human resources, legal, risk, finance, audit and operations departments were included in the review to ensure accuracy and completeness of the scope and findings. The assessment demonstrated that our compensation programs are designed to minimize financial and reputational risks and do not create risks that are reasonably likely to have a material adverse effect on the Company.

Our management is responsible for day-to-day risk management and operates under an ERM program that addresses strategic, operational, financial and compliance risks. The ERM program includes practices to identify risks, assesses the impact and probability of occurrence, and develops action plans to prevent the occurrence or mitigate the impact of the risk. The ERM program includes regular reporting to our senior management team and includes monitoring and testing by the Chief Risk Officer and Risk Management, Compliance and Internal Audit groups. The Chief Risk Officer reviews the overall ERM program with the Board of Directors on a regular basis.

We believe the division of risk management responsibilities described above is an effective approach for addressing the risks facing our Company.

Director Nominees

The Governance Committee uses a variety of methods for identifying and evaluating nominees for director. The Governance Committee regularly assesses the appropriate size of the Board and whether any vacancies on the Board are expected due to retirement or otherwise. In the event vacancies are anticipated, or otherwise arise, the Governance Committee considers various potential candidates for director. Board candidates are considered based upon various criteria, including diverse business, administrative and professional skills or experiences; an understanding of relevant industries, technologies and markets; financial literacy; independence status; the ability and willingness to contribute time and special competence to Board activities; personal integrity and independent judgment; and a commitment to enhancing shareholder value. The Governance Committee considers these and other factors as it deems appropriate, given the needs of the Board. Our goal is a balanced and diverse Board, with members whose skills, background and experience are complementary and, together, cover the spectrum of areas that impact our business currently and in the future. The Governance Committee considers candidates for Board membership suggested by a variety of sources, including current or past Board members, the use of third-party executive search firms, members of management and shareholders. Any shareholder may make recommendations for consideration by the Governance Committee for membership on the Board by sending a written statement of the qualifications of the recommended individual to the Corporate Secretary. There are no differences in the manner by which the Committee evaluates director candidates recommended by shareholders from those recommended by other sources.

Shareholders who intend to nominate persons for election to the Board of Directors must provide timely written notice of the nomination in accordance with Article I, Section 9 of our Bylaws. Generally, our Corporate Secretary must receive the written notice at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders. For the 2020 shareholder meeting, those dates are January 31, 2020 and January 1, 2020. The notice must set forth at a minimum the information set forth in Article I, Section 9 of our Bylaws, including the shareholder's identity and status, contingent ownership interests, description of any agreement made with others acting in concert with respect to the nomination, specific information about the nominee and certain representations by the nominee to us.

Communications with the Board

Shareholders and others interested in communicating directly with the Lead Director, with the independent directors as a group, or the Board of Directors may do so in writing to the Lead Director, Black Hills Corporation, 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709.

Corporate Governance Documents

The charters of the Audit, Compensation and Governance Committees, as well as the Corporate Governance Guidelines of the Board of Directors, Policy for Director Independence, Code of Business Conduct and the Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and certain other persons performing similar functions can be found in the "Governance" section of our website (www.blackhillscorp.com/investor-relations/corporate-governance). We intend to disclose any amendments to, or waivers of, the Code of Ethics on our website. Please note that none of the information contained on our website is incorporated by reference in this proxy statement.

The Corporate Governance Guidelines include a plurality plus voting policy. Pursuant to the policy, any nominee for election as a director in an uncontested election who receives a greater number of votes "Withheld" from his or her election than votes "For" his or her election will promptly tender his or her resignation as a director to the Chairman of the Board following certification of the election results. Broker non-votes will not be deemed to be votes "For" or "Withheld" from a director's election for purposes of the policy. The Governance Committee (without the participation of the affected director) will consider each resignation tendered under the policy and recommend to the Board whether to accept or reject it. The Board will then take the appropriate action on each tendered resignation, taking into account the Governance Committee's recommendation. The Governance Committee in making its recommendation, and the Board in making its decision, may consider any factors or other information that it considers appropriate, including the reasons why the Governance Committee believes shareholders "Withheld" votes for election from such director and any other circumstances surrounding the "Withheld" votes, any alternatives for curing the underlying cause of the "Withheld" votes, the qualifications of the tendering director, his or her past and expected future contributions to us and the Board, and the overall composition of the Board, including whether accepting the resignation would cause us to fail to meet any applicable SEC or NYSE requirements. The Board will publicly disclose by filing with the SEC on Form 8-K its decision and, if applicable, its rationale within 90 days after receipt of the tendered resignation.

Certain Relationships and Related Party Transactions

We recognize related party transactions can present potential or actual conflicts of interest and create the appearance that decisions are based on considerations other than the best interests of us and our shareholders. Accordingly, as a general matter, it is our preference to avoid related party transactions. Nevertheless, we recognize that there are situations where related party transactions may be in, or may not be inconsistent with, the best interests of us and our shareholders, including but not limited to situations where we may obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to related parties on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. Therefore, our Board of Directors has adopted a policy for the review of related party transactions. This policy requires directors and officers to promptly report to our General Counsel all proposed or existing transactions in which the Company and they, or persons related to them, are parties or participants. Our General Counsel presents to our Governance Committee those transactions that may require disclosure pursuant to Item 404 of Regulation S-K (typically, those transactions that exceed $120,000). Our Governance Committee reviews the material facts presented and either approves or disapproves entry into the transaction. In reviewing the transaction, the Governance Committee considers the following factors, among other factors it deems appropriate: (i) whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third party under the same or similar circumstances; (ii) the extent of the related party's interest in the transaction; and (iii) the impact on a director's independence in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer.

Section 16(a) Beneficial Ownership Reporting Compliance

Based solely upon a review of our records and copies of reports on Form 3, 4 and 5 furnished to us, we believe that during and with respect to 2018, all persons subject to the reporting requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, filed the required reports on a timely basis, except for a Form 4 for Jennifer C. Landis, Senior Vice President - Chief Human Resources Officer, reporting the acquisition of 127 shares through the vesting of a restricted stock grant in the month of February 2017.

MEETINGS AND COMMITTEES OF THE BOARD

THE BOARD OF DIRECTORS

Our directors review and approve our strategic plan and oversee our management. Our Board of Directors held four in-person meetings and three telephonic meetings during 2018. Each regularly scheduled meeting of the Board includes an executive session of only independent directors. We encourage our directors to attend the annual shareholders' meeting. During 2018, each current director attended at least 75 percent of the combined total of Board meetings and Committee meetings on which the director served and all directors then serving attended the 2018 annual meeting of shareholders.

COMMITTEES OF THE BOARD

Our Board has three standing committees to facilitate and assist the Board in the execution of its responsibilities. The committees are currently the Audit Committee, the Compensation Committee and the Governance Committee. In accordance with the NYSE listing standards and our Corporate Governance Guidelines, the Audit, Compensation and Governance Committees are comprised solely of independent directors. Each committee operates under a charter, which is available on our website at www.blackhillscorp.com/investor-relations/corporate-governance and is also available in print to any shareholder who requests it. In addition, our Board creates special committees from time to time for specific purposes. Members of the committees are designated by our Board upon recommendation of the Governance Committee.

AUDIT COMMITTEE		
Committee Chair:		
Steven R. Mills	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Robert P. Otto, Mark A. Schober, John B. Vering	4	4

Primary Responsibilities

- assist the Board in fulfilling its oversight responsibility to our shareholders relating to the quality and integrity of our accounting, auditing and financial reporting practices;
- oversee the integrity of our financial statements, financial reporting process, systems of internal controls and disclosure controls regarding finance, accounting and legal compliance;
- review areas of potential significant financial risk to us;
- review consolidated financial statements and disclosures;
- appoint an independent registered public accounting firm for ratification by our shareholders;
- monitor the independence and performance of our independent registered public accountants and internal auditing department;
- pre-approve all audit and non-audit services provided by our independent registered public accountants;
- review the scope and results of the annual audit, including reports and recommendations of our independent registered public accountants;
- review the internal audit plan, results of internal audit work and our process for monitoring compliance with our Code of Business Conduct and other policies and practices established to ensure compliance with legal and regulatory requirements; and
- periodically meet, in private sessions, with our internal audit group, Chief Financial Officer, Chief Compliance Officer, other management, and our independent registered public accounting firm.

In accordance with the rules of the NYSE, all of the members of the Audit Committee are financially literate. In addition, the Board determined that Messrs. Mills, Schober and Vering have the requisite attributes of an “audit committee financial expert” as provided in regulations promulgated by the SEC, and that such attributes were acquired through relevant education and/or experience.

COMPENSATION COMMITTEE		
Committee Chair:		
Michael H. Madison	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Rebecca B. Roberts, Teresa A. Taylor, Thomas J. Zeller	2	2

Primary Responsibilities

- discharge the Board of Directors’ responsibilities related to executive and director compensation philosophy, policies and programs;
- perform functions required of directors in the administration of all federal and state laws and regulations pertaining to executive employment and compensation;
- consider and recommend for approval by the Board all executive compensation programs including executive benefit programs and stock ownership plans; and
- promote an executive compensation program that supports the overall objective of enhancing shareholder value.

The Compensation Committee has authority under its charter to retain and terminate compensation consultants, outside counsel and other advisors as the Committee may deem appropriate in its sole discretion. The Committee has sole authority to approve related fees and retention terms and may delegate any of its responsibilities to subcommittees as the Committee may deem appropriate. In addition, pursuant to SEC rules and NYSE listing standards regarding the independence of compensation committee advisors, the Committee has the responsibility to consider the independence of any compensation advisor before engaging the advisor.

The Committee engaged Willis Towers Watson, an independent consulting firm, to conduct an annual review of our 2018 total compensation program for executive officers and directors. The Committee reviewed the independence of Willis Towers Watson and the individual representative of Willis Towers Watson who serves as a consultant to the Committee, in accordance with the SEC and NYSE requirements and the specific factors that the requirements cite. The Compensation Committee concluded that Willis Towers Watson is independent and Willis Towers Watson's performance of services raises no conflict of interest. The Committee's conclusion was based in part on a report that Willis Towers Watson provided to the Committee intended to reveal any potential conflicts of interest and a schedule provided by management of the type and amount of non-executive compensation services provided by Willis Towers Watson to the Company. During 2018, the cost of these non-executive compensation services was less than $25,000.

The Committee annually evaluates the CEO’s performance against Board-established goals and objectives, with input from the other independent directors. Based upon the Committee’s evaluation and recommendation, the independent directors of the Board set the CEO’s annual compensation, including salary, bonus, incentive and equity compensation.

The CEO annually reviews the performance of each of our executive officers and presents a summary of his evaluations to the Committee. Based upon these performance reviews, market analysis conducted by the compensation consultant and discussions with our Sr. Vice President, Chief Human Resources Officer, the CEO recommends the compensation of the executive officers to the Committee. The Committee may exercise its discretion in modifying any of the recommended compensation and award levels in its review and approval process.

More information describing the Compensation Committee’s processes and procedures for considering and determining executive compensation, including the role of our CEO and consultants in determining or recommending the amount or form of executive compensation, is included in the Compensation Discussion and Analysis.

In setting non-employee director compensation, the Compensation Committee recommends the form and amount of compensation to the Board of Directors, which makes the final determination. In considering and recommending the compensation of non-employee directors, the Compensation Committee considers such factors as it deems appropriate, including historical compensation information, level of compensation necessary to attract and retain non-employee directors meeting our desired qualifications and market data. In the review of director compensation in 2018, the Compensation Committee retained Willis Towers Watson to provide market information on non-employee director compensation, including compensation structure, annual board and committee retainers, committee chair fees, and stock-based compensation.

Compensation Committee Interlocks and Insider Participation. The Compensation Committee is comprised entirely of independent directors. In addition, none of our executive officers serve as a member of a board of directors or compensation committee of any entity that has one or more executive officers who serve on our Board or on our Compensation Committee.

GOVERNANCE COMMITTEE		
Committee Chair:		
Rebecca B. Roberts	Total Meetings Held	
Additional Committee Members:	In-Person	Telephonic
Michael H. Madison, John B. Vering, Thomas J. Zeller	3	1

Primary Responsibilities

- assess the size of the Board and membership needs and qualifications for Board membership;
- identify and recommend prospective directors to the Board to fill vacancies;
- review and evaluate director nominations submitted by shareholders, including reviewing the qualifications and independence of shareholder nominees;
- consider and recommend existing Board members to be renominated at our annual meeting of shareholders;
- consider the resignation of an incumbent director who makes a principal occupation change (including retirement) or who receives a greater number of votes "Withheld" than votes "For" in an uncontested election of directors and recommend to the Board whether to accept or reject the resignation;
- establish and review guidelines for corporate governance;
- recommend to the Board for approval committee membership and chairs of the committees;
- recommend to the Board for approval an independent director to serve as a Lead Director;
- review the independence of each director and director nominee;
- administer an annual evaluation of the performance of the Board and each Committee and a biannual evaluation of each individual director; and
- ensure that the Board oversees the evaluation and succession planning of management.

DIRECTOR COMPENSATION

DIRECTOR FEES

Compensation to our non-employee directors consists of cash retainers for Board members, Committee members, the Lead Director and Committee Chairs. In addition, the Board members receive common stock equivalents that are deferred until after they leave the Board. Dividend equivalents accrue on the common stock equivalents. We do not pay meeting fees.

In 2018, Willis Towers Watson completed a market compensation review of our peer companies' director fees. Based on this review, the cash retainer, the equity component of the directors' fees, and the Audit Committee Chair retainer fee were increased effective January 1, 2019 to more closely align with the median director compensation for our peer utility companies. The fee structure for director fees in 2018 and the new fees effective January 1, 2019 are as follows:

	2018 Fees		Fees Effective January 1, 2019	
	Cash	Common Stock Equivalents	Cash	Common Stock Equivalents
Board Retainer	$70,000	$92,500	$80,000	$105,000
Lead Director Retainer	$25,000		$25,000	
Committee Chair Retainer				
Audit Committee	$12,500		$15,000	
Compensation Committee	$10,000		$10,000	
Governance Committee	$7,500		$7,500	
Committee Member Retainer				
Audit Committee	$10,000		$10,000	
Compensation Committee	$7,500		$7,500	
Governance Committee	$7,500		$7,500	

DIRECTOR COMPENSATION FOR 2018 AND COMMON STOCK EQUILAVENTS OUTSTANDING AS OF DECEMBER 31, 2018[(1)]

Name[(2)]	Fees Earned or Paid in Cash	Stock Awards[(3)]	Total	Number of Common Stock Equivalents Outstanding at December 31, 2018[(4)]
Michael H. Madison	$95,000	$92,500	$187,500	11,012
Linda K. Massman[(5)]	$38,750	$46,250	$85,000	5,615
Steven R. Mills	$92,500	$92,500	$185,000	12,361
Robert P. Otto	$80,000	$92,500	$172,500	2,948
Rebecca B. Roberts	$92,500	$92,500	$185,000	13,381
Mark A. Schober	$80,000	$92,500	$172,500	5,053
Teresa A. Taylor	$77,500	$92,500	$170,000	3,421
John B. Vering	$112,500	$92,500	$205,000	25,891
Thomas J. Zeller	$85,000	$92,500	$177,500	31,052

(1) Our directors did not receive any stock option awards, non-equity incentive plan compensation, pension benefits or perquisites in 2018 and did not have any stock options outstanding at December 31, 2018.

(2) Mr. Emery, our Executive Chairman and Mr. Evans, our President and CEO, are not included in this table because they are our employees and thus receive no compensation for their services as directors. Mr. Emery’s and Mr. Evan's compensation received as employees is shown in the Summary Compensation Table for our Named Executive Officers.

(3) Each non-employee director received a quarterly award of common stock equivalents with a grant date fair value of $23,125 per quarter, equivalent to $92,500 per year. The grant date fair value of a common stock equivalent is the closing price of a share of our common stock on the grant date.

(4) The common stock equivalents are fully vested in that they are not subject to forfeiture; however, the shares are not issued until after the director ends his or her service on the Board. The common stock equivalents are payable in stock or cash or can be deferred further at the election of the director.

(5) Ms. Massman resigned as a member of the Board of Directors effective July 1, 2018; consequently her fees earned and stock award fair values reflect a partial year of service.

DIRECTOR STOCK OWNERSHIP GUIDELINES

Each member of our Board of Directors is required to apply at least 50 percent of his or her annual cash retainer toward the purchase of shares of common stock until the director has accumulated shares of common stock or common stock equivalents equal to five times the annual cash Board retainer. Currently, all of our directors have met the stock ownership guideline except for Ms. Taylor and Mr. Otto, who have been on the Board for less than 3.5 years.

SECURITY OWNERSHIP OF MANAGEMENT AND PRINCIPAL SHAREHOLDERS

The following tables set forth the beneficial ownership of our common stock as of February 25, 2019 for each director, each executive officer named in the Summary Compensation Table, all of our directors and executive officers as a group and each person or entity known by us to beneficially own more than five percent of our outstanding shares of common stock. Beneficial ownership includes shares a director or executive officer has or shares the power to vote or transfer. There were no stock options outstanding for any of our directors or executive officers as of February 25, 2019.

Except as otherwise indicated by footnote below, we believe that each individual or entity named has sole investment and voting power with respect to the shares of common stock indicated as beneficially owned by that individual or entity.

Name of Beneficial Owner(1)	Shares of Common Stock Beneficially Owned(2)	Directors Common Stock Equivalents(3)	Total	Percentage
Outside Directors				
Michael H. Madison	15,220	11,012	26,232	*
Steven R. Mills	13,127	12,361	39,359	*
Robert P. Otto	1,452	2,948	4,400	*
Rebecca B. Roberts	4,648	13,381	18,029	*
Mark A. Schober	2,488	5,053	7,541	*
Teresa A. Taylor	1,618	3,421	5,039	*
John B. Vering	10,995	25,891	36,886	*
Thomas J. Zeller	10,398	31,052	41,450	*
Named Executive Officers				
Scott A. Buchholz	38,668		38,668	*
David R. Emery	205,567		205,567	*
Linden R. Evans	111,635		111,635	*
Brian G. Iverson	32,577		32,577	*
Richard W. Kinzley	47,354		47,354	*
All directors and executive officers as a group (14 persons)	506,508	105,119	611,627	1.0%

* Represents less than one percent of the common stock outstanding.

(1) Beneficial ownership means the sole or shared power to vote, or to direct the voting of, a security or investment power with respect to a security.

(2) Includes restricted stock held by the following executive officers for which they have voting power but not investment power: Mr. Buchholz 3,857 shares; Mr. Emery 17,228 shares; Mr. Evans 18,176 shares; Mr. Iverson 6,107 shares; Mr. Kinzley 7,912 shares; and all directors and executive officers as a group 55,942 shares.

(3) Represents common stock allocated to the directors' accounts in the directors' stock-based compensation plan, of which there are no voting rights.

PRINCIPAL SHAREHOLDERS

Set forth in the table below is information about the number of shares held by persons we know to be the beneficial owners of more than 5% of the issued and outstanding Common Stock.

Name and Address	Shares of Common Stock Beneficially Owned	Percentage
BlackRock, Inc.[1] 55 East 52nd Street New York, NY 10055	7,869,750	13.1%
State Street Corporation[2] State Street Financial Center One Lincoln Street Boston, MA 02111	5,282,711	8.8%
The Vanguard Group Inc.[3] 100 Vanguard Blvd. Malvern, PA 19355	5,764,207	9.6%

(1) Information is as of December 31, 2018, and is based on a Schedule 13G/A filed on January 24, 2019.
(2) Information is as of December 31, 2018, and is based on a Schedule 13G filed on February 13, 2019.
(3) Information is as of December 31, 2018, and is based on a Schedule 13G/A filed on February 11, 2019.

PROPOSAL 2	RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The firm of Deloitte & Touche LLP, independent registered public accountants, conducted the audit of Black Hills Corporation and its subsidiaries for 2018. Representatives of Deloitte & Touche LLP will be present at our annual meeting and will have the opportunity to make a statement, if they desire to do so, and to respond to appropriate questions.

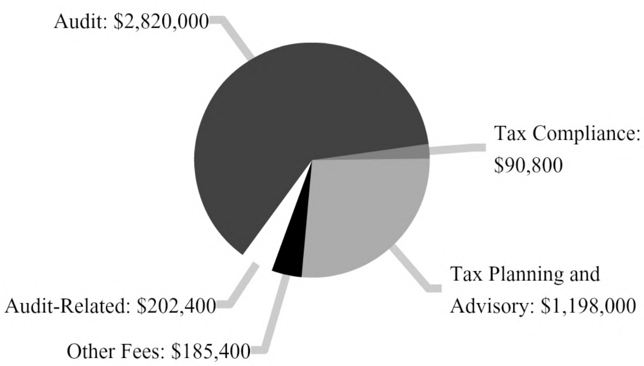
Our Audit Committee has appointed Deloitte & Touche LLP to perform an audit of our consolidated financial statements and those of our subsidiaries for 2019 and to render their reports. The Board of Directors recommends ratification of the Audit Committee's appointment of Deloitte & Touche LLP. The appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2019 will be ratified if the votes cast "For" exceed the votes cast "Against." Abstentions will have no effect on such vote. If shareholder approval for the appointment of Deloitte & Touche LLP is not obtained, the Audit Committee will reconsider the appointment.

The Board of Directors recommends a vote *FOR* ratification of the appointment of Deloitte & Touche LLP to serve as our independent registered public accounting firm for 2019.

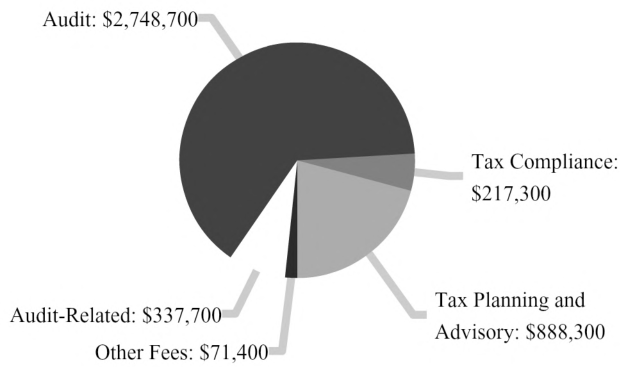
FEES PAID TO THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The following chart sets forth the aggregate fees for services provided to us for the years ended December 31, 2018 and 2017 by our independent registered public accounting firm, Deloitte & Touche LLP:

2018 Deloitte & Touche LLP Fees
Total $4,496,600



2017 Deloitte & Touche LLP Fees
Total $4,263,400



Audit Fees
Fees for professional services rendered for the audits of our financial statements, review of the interim financial statements included in quarterly reports, opinions on the effectiveness of our internal control over financial reporting, and services that generally only the independent auditor can reasonably provide, such as comfort letters, statutory audits, consents and assistance with and review of documents filed with the SEC.

Audit-Related Fees
Fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported under “Audit Fees.” These services include employee benefit plan audits and certain regulatory audits.

Tax Compliance Fees
Fees for services related to federal and state tax compliance planning and advice and review of tax returns.

Tax Planning and Advisory Fees
Fees for planning and advisory services primarily related to partnership restructuring and jurisdictional simplification and consolidation related to prior acquisitions.

Other Fees
Fees for advising the Company as it defines the Governance, Risk and Compliance ("GRC") requirements for a GRC software tool.

The services performed by Deloitte & Touche LLP were pre-approved in accordance with the Audit Committee’s pre-approval policy whereby the Audit Committee pre-approves all audit and permissible non-audit services provided by the independent registered public accountants. The Audit Committee will generally pre-approve a list of specific services and categories of services, including audit, audit-related, tax and other services, for the upcoming or current year, subject to a specified cost level. Any service that is not included in the approved list of services must be separately pre-approved by the Audit Committee.

AUDIT COMMITTEE REPORT

The Audit Committee assists the Board of Directors in fulfilling its oversight responsibilities to shareholders relating to the integrity of the Company's financial statements, the Company's compliance with legal and regulatory requirements regarding financial reporting, the independent auditors' qualifications and independence, and the performance of the Company's internal and independent auditors.

Management has the primary responsibility for the completeness and accuracy of the Company's financial statements and disclosures, the financial reporting process, and the effectiveness of the Company's internal control over financial reporting.

Our independent auditors, Deloitte & Touche LLP, are responsible for auditing the Company’s consolidated financial statements and expressing an opinion as to whether they are presented fairly, in all material respects, in conformity with accounting principles generally accepted in the United States.

In fulfilling its oversight responsibilities for 2018, the Audit Committee, among other things:

- Reviewed and discussed the audited financial information contained in the Annual Report on Form 10-K with management and our independent auditors prior to public release.
- Reviewed and discussed with our independent auditors their judgments as to the quality, not just the acceptability, of our critical accounting principles and estimates and all other communications required to be discussed with the Audit Committee under generally accepted auditing standards, including the matters required to be discussed by applicable Public Company Accounting Oversight Board Standards.
- Reviewed and discussed with management, our internal auditors and our independent auditors management's report on internal control over financial reporting, including the significance and status of control deficiencies identified by management and the results of remediation efforts undertaken, to determine the effectiveness of internal control over financial reporting at December 31, 2018.
- Reviewed with our independent auditors their report on the Company's internal control over financial reporting at December 31, 2018, including the basis for their conclusions.
- Reviewed and pre-approved all audit and non-audit services and fees provided to the Company by our independent auditors and considered whether the provision of such non-audit services by our independent auditors is compatible with maintaining their independence.
- Discussed with our internal and independent auditors their audit plans, audit scope and identification of audit risks and reviewed the results of internal audit examinations.
- Reviewed and discussed the interim financial information contained in each quarterly earnings announcement and Quarterly Report on Form 10-Q with management and our independent auditors prior to public release.
- Received and reviewed periodic corporate compliance and financial risk reports, including credit and hedging activity.
- Held private sessions with our independent auditors, Chief Auditor, Chief Financial Officer and Controller, and Chief Compliance Officer.
- Received the written disclosures and the letter from our independent auditors required by the applicable requirements of the Public Company Accounting Oversight Board regarding the independent auditors' communications with the Committee concerning independence and discussed the independence of Deloitte & Touche LLP with them.
- Concluded Deloitte & Touche LLP is independent based upon the above considerations.

Based upon the reviews and discussions referred to above, the Audit Committee recommended to the Board that our audited consolidated financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2018 filed with the SEC. The Audit Committee also recommended and the Board reappointed Deloitte & Touche LLP as our independent registered public accounting firm for 2019. Shareholders are being asked to ratify that selection at the 2019 Annual Meeting.

THE AUDIT COMMITTEE

Steven R. Mills, Chair
Robert P. Otto
Mark A. Schober
John B. Vering

COMPENSATION DISCUSSION AND ANALYSIS

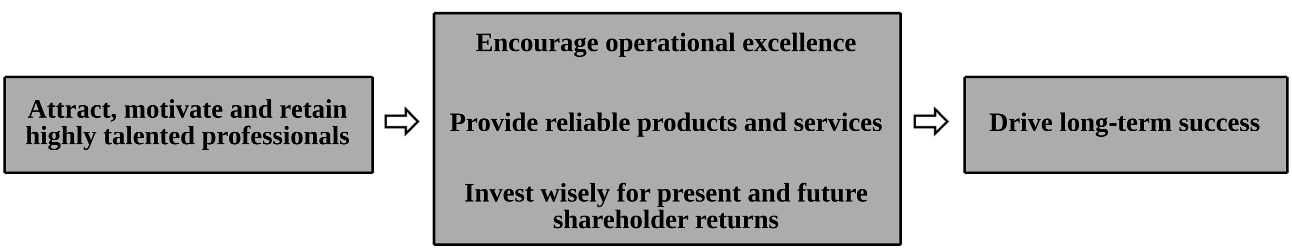
INTRODUCTION

This Compensation Discussion and Analysis describes our overall executive compensation policies and practices and specifically explains the compensation-related actions taken with respect to 2018 compensation for our executive officers included in the Summary Compensation Table (our “Named Executive Officers”). Our Named Executive Officers, based on 2018 positions and compensation levels, are:

Name Executive Officers	Title	Reference
David R. Emery	Chairman and Chief Executive Officer	Emery, CEO
Richard W. Kinzley	Sr. Vice President and Chief Financial Officer	Kinzley, CFO
Linden R. Evans	President and Chief Operating Officer	Evans, COO
Brian G. Iverson	Sr. Vice President and General Counsel	Iverson, GC
Scott A. Buchholz	Sr. Vice President and Chief Information Officer	Buchholz, CIO

The Compensation Committee of the Board of Directors (the “Committee,” for purposes of this Compensation Discussion and Analysis) is composed entirely of independent directors and is responsible for approving and overseeing our executive compensation philosophy, policies and programs.

OVERALL GOAL



EXECUTIVE COMPENSATION PROGRAM DESIGN OBJECTIVES

Attract, retain, motivate and encourage the development of highly qualified executives

Provide competitive compensation

Promote the relationship between pay and performance

Promote corporate performance that is linked to our shareholders' interests

Recognize and reward individual performance

2018 ACCOMPLISHMENTS

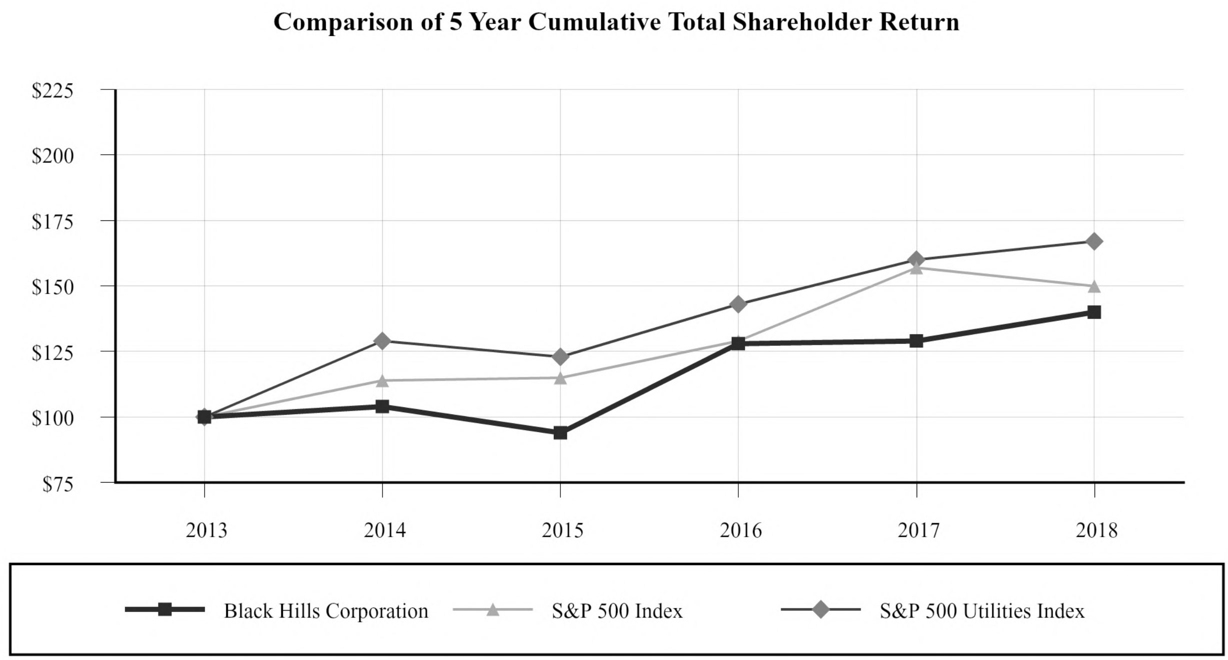
Black Hills Corporation had a strong year in 2018. Substantial progress was made on our strategic initiatives and we continued to lay a solid foundation for strong future earnings growth. Significant accomplishments for the year included:

- GAAP Income from continuing operations was $4.78 per diluted share in 2018 compared to $3.52 per diluted share in 2017, and earnings per share from continuing operations, as adjusted[(1)] was $3.54 per diluted share in 2018 compared to $3.36 per diluted share in 2017, an increase of 5.4 percent[(1)];
- Increased the annual dividend for the 48th consecutive year, one of the longest records in the utility sector;
- Issued 6.37 million shares of new common stock related to the conversion of 5.98 million equity units that were issued in 2015 to partially fund our acquisition of SourceGas;
- Completed the exit of our Oil and Gas business;
- Invested in our utility infrastructure and systems:
  * Deployed $510 million in capital projects;
  * Commenced construction of the 60 MW Busch Ranch II wind project;
  * Completed the construction of the first 81 miles of a 175-mile 230 kV transmission line from Rapid City, South Dakota to Segall, Nebraska;
- Executed a number of regulatory accomplishments;
  * Successfully completed rate review requests for Arkansas Gas, Northwest Wyoming Gas, and Rocky Mountain Natural Gas;
  * Received approval to legally consolidate Colorado Gas and Colorado Gas Distribution;
  * Received approval to extend the recovery period for Nebraska Gas Distribution's system safety and integrity rider;
  * Received approval for Kansas Gas to double eligible system integrity and safety investments up to $8 million per year;
  * Received approval from the Wyoming Public Service Commission to construct a $53 million 35-mile natural gas pipeline from Douglas, Wyoming to existing facilities near Casper, Wyoming;
  * Filed Wyoming Electric's 2018 integrated resource plan;
  * Filed for approval of new Renewable Ready Service Tariffs in South Dakota and Wyoming;
  * Filed an application in Wyoming for approval to construct a $57 million, 40 MW Corriedale wind farm;
  * Finalized agreements with six state utility regulators to deliver federal corporate income tax reform benefits from the Tax Cuts and Jobs Act to utility customers;
- Provided the safe and reliable service our communities and customers depend on and achieved several notable operations performance metrics:
  * Earned 1st Quartile reliability ranking for our three electric utilities compared to industry averages;
  * Achieved a safety performance total case incident rate of 1.2 compared to an industry average of 2.1;
  * Achieved a 7 percent Net Promotor Score improvement over 2017;
  * Achieved a power generation fleet availability of 90 percent for our coal-fired generation, 96 percent for our gas-fired generation, 99.5 percent for our diesel-fired generation and 94 percent for our wind generation; all above industry averages with the exception of wind generation which was slightly below the industry average of 96 percent;
  * Received an award from the State of Wyoming for nine years without a lost-time accident at our mine; received the State Mine Inspector’s Award for the fifth year in a row for operating the safest small mine; received the Mine Safety and Health Administration’s Certificate of Achievement for no lost-time accidents; and
- Named to Forbes America's Best Midsize Employers 2018 Top 250 List.

[(1)] Earnings per share from continuing operations, as adjusted, is a non-GAAP measure. See Appendix A for a reconciliation of the non-GAAP measure to our results as reported under the GAAP.

RETURN TO SHAREHOLDERS

The following chart shows how a $100 investment in the Company's common stock on December 31, 2013 would have grown to $140 on December 31, 2018, with dividends reinvested. The chart also compares the total shareholder return on the Company's common stock to the same investment in the S&P 500 Index and S&P 500 Utilities Index over the same period.



2018 PERFORMANCE RESULTS

Our corporate financial goals are used as measures to determine awards under our variable pay programs. The following table summarizes our 2018 performance measures and results.

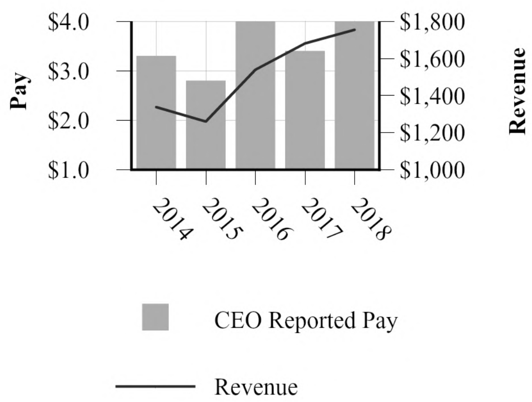
Pay Element	Performance Measure	2018 Results
Short-term Incentive	EPS from ongoing operations, as adjusted, target set at $3.43; threshold set at $3.09	$3.54 per share for incentive plan purposes Payout of 133% of Target
Long-term Incentive - Performance Share Award	Total Shareholder Return (TSR) relative to our Performance Peer Group measured over a three-year period	TSR 62% 75th Percentile Ranking in Performance Peer Group 162% Payout

PAY FOR PERFORMANCE

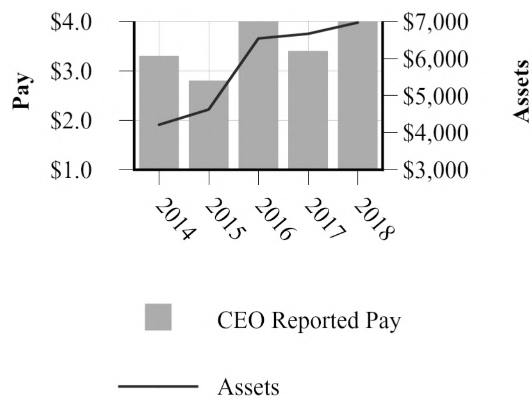
A key component of our executive compensation program is to link pay to performance.

The charts below illustrate the directional relationship between the compensation of our CEO as reported in the Summary Compensation Table (excluding the change in pension value) and the growth in our Company for the last five years.

CEO Reported Pay vs. Revenue
(in millions)

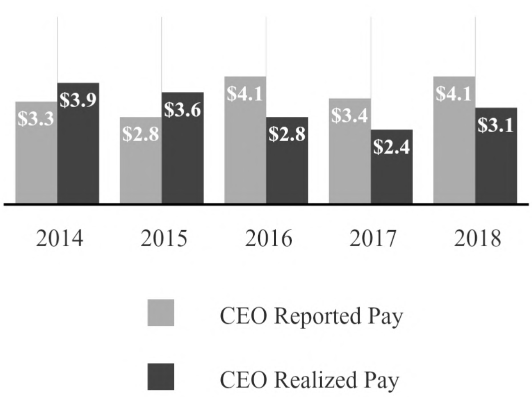


CEO Reported Pay vs. Assets
(in millions)

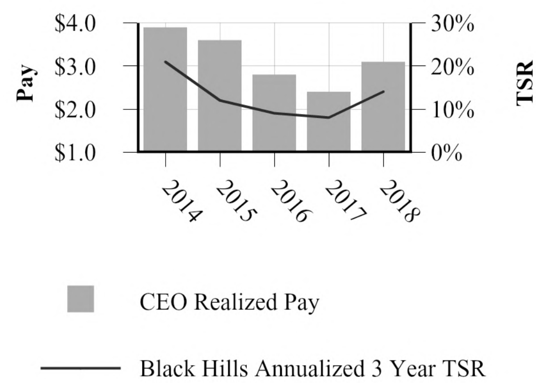


Since a large percentage of the CEO's pay as reported in the Summary Compensation Table represents potential pay, we believe it is also important to look at pay actually realized each year. In addition, since over 50 percent of our CEO pay is tied to Company performance, it is important to look at his realized pay as it is impacted by Company performance. The following graphics show reported pay and realized pay over the last five years and realized pay as it correlates to the Company's annualized 3-year total shareholder return, its long-term performance metric.

CEO Reported vs. Realized Pay
(in millions)



CEO Realized Pay
vs. Annualized 3-Year TSR
(in millions)



Reported pay includes base salary, actual annual incentive earned, the grant date fair value of long-term equity compensation and all other compensation, excluding the change in pension value, each as reported in the Summary Compensation Table.

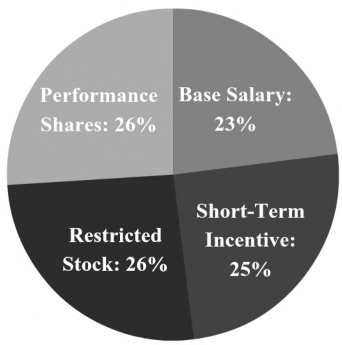
Realized pay includes base salary, actual annual incentive earned and all other compensation, each as reported in the Summary Compensation Table, and the value of long-term performance compensation paid and stock awards vested in the applicable year.

KEY EXECUTIVE COMPENSATION OBJECTIVES AND 2018 COMPENSATION DECISIONS

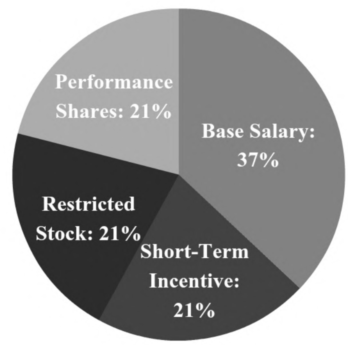
Overall, our goal is to target total direct compensation (the sum of base salary, short-term incentive at target and long-term incentive at target) at the median of the appropriate market when our operating results approximate average performance in relation to our peers.

Our executive compensation is designed to maintain an appropriate and competitive balance between fixed and variable compensation components, short- and long-term compensation, and cash and stock-based compensation.

CEO 2018 Target Pay Mix



Other NEOs 2018 Target Pay Mix



Variable	77%	Variable	63%
Linked to Share Value	52%	Linked to Share Value	42%

We believe that the performance basis for determining compensation should differ by each reward component – base salary, short-term incentive and long-term incentive. Incentive measures (short-term and long-term) should emphasize objective, quantitative operating measures. The performance measures for our incentive compensation plans are as follows:

<u>Base Salary</u>

Our CEO recommended, and our Board concurred, that our Named Executive Officers not receive base salary merit increases in 2018 due to poor stock performance and other challenges in 2017. The competitive market assessment also indicated base salaries were generally aligned with the utility industry median. The individual base salaries reflect the individual's performance, tenure, experience and market compensation for comparable positions in our industry and Compensation Peer Group.

<u>Short-Term Incentive</u>

The short-term incentive is based on earnings per share targets. The Committee believes that this performance measure closely aligns the executives’ and our shareholders’ interests and fosters teamwork and cooperation.

* The 2018 short-term target incentive as a percent of base pay remained the same as the prior year at 110 percent, 60 percent, 70 percent and 50 percent for our CEO, CFO, COO, and CIO, respectively. It was increased for our GC from 45 percent to 55 percent, adjusting to approximate the market median.
* Based on the attainment of pre-established performance goals, the actual payout can range from 50 percent to 200 percent of target.
* The Committee selected an earnings per share goal based on ongoing operations, as adjusted, of $3.43 as the 2018 corporate target goal.
* Our 2018 earnings for the Short-Term Incentive Plan were $3.54 per share, which was 3 percent above our target earnings per share goal, resulting in a payout of 133 percent of target.

Long-Term Incentive

The long-term incentive is delivered 50 percent in performance shares and 50 percent in restricted stock that vests ratably over a three-year service period. Performance share awards are based on our total shareholder return over a three-year performance period compared to our Performance Peer Group. This performance measure was chosen because it mirrors the market return of our shareholders and compares our performance to that of our Performance Peer Group. Target payout occurs if our performance is at the 50th percentile of our Performance Peer Group.

* 2018 Long-Term Incentive Value
  The 2018 long-term target incentive stayed the same for the CEO and was adjusted for all the Named Executive Officers reflecting the market median compensation levels.

* Performance Share Plan Payment
  Our total shareholder return under the performance plan criteria for the three-year period, January 1, 2016 through December 31, 2018, was 62 percent, which ranked at the 75th percentile of our Performance Peer Group resulting in a 162 percent payout.

* Restricted Stock Grant
  Consistent with prior years, the Committee awarded 50 percent of the Named Executive Officers' long-term incentive in restricted stock that ratably vests over three years.

Governance Best Practices

We have several governance programs in place to align our executive compensation with shareholder interests and to mitigate risks in our plans. These programs include stock ownership guidelines, clawback provisions in our short-term and long-term incentive award agreements, and the prohibition of hedging or pledging of Company stock.

Summary

In total, the Committee believes that the 2018 compensation actions, decisions and outcomes strongly reflect and reinforce our compensation philosophy and, in particular, emphasize the alignment between compensation and both performance and shareholder interests. At our 2018 annual meeting, shareholders owning 96 percent of the shares voted on this matter approved our executive compensation for 2017, which we consider highly supportive of our current compensation philosophy. In connection with establishing the 2018 executive compensation program, the Board reviewed the results of the say on pay vote, as well as market data and performance indicators. No significant design changes were made.

SETTING EXECUTIVE COMPENSATION

Based upon our compensation philosophy, the Committee structures our executive compensation to motivate our officers to achieve specified business goals and to reward them for achieving such goals. The key steps the Committee follows in setting executive compensation are to:

Analyze executive compensation market data to ensure market competitiveness

Review the components of executive compensation, including base salary, short-term incentive, long-term incentive, retirement and other benefits

Review total compensation mix and structure

Review executive officer performance, responsibilities, experience and other factors cited above to determine individual compensation levels

Market Compensation Analysis

The market for our senior executive talent is national in scope and is not focused on any one geographic location, area or region of the country. As such, our executive compensation should be competitive with the national market for senior executives. It should also reflect the executive's responsibilities and duties and align with the compensation of executives at companies or business units of comparable size and complexity. The Committee gathers market information for our corporate executives from the electric and gas utility industry and also reviews general industry data as an additional reference.

The Committee selects and retains the services of an independent consulting firm to periodically:

Provide information regarding practices and trends in compensation programs

Review and evaluate our compensation program as compared to compensation practices of other companies with similar characteristics, including size, complexity and type of business

Review and assist with the establishment of a peer group of companies

Provide a compensation analysis of the executive positions

The Committee used the services of Willis Towers Watson to evaluate 2018 compensation. Willis Towers Watson gathered data from nationally recognized survey providers, as well as specific peer companies through public filings, which included:

i. Willis Towers Watson's 2017 Compensation Data Bank (energy services and general industry); and
ii. 24 peer companies representing the utility and energy industry.

The 24 peer companies ranged in annual revenue size from approximately $545 million to $6.4 billion, with the median at $1.9 billion. The Company's 2017 revenue was $1.7 billion. The survey data was adjusted for our relative revenue size using regression analysis. Our compensation peer companies included in the analysis for 2018 compensation decisions were:

ALLETE Inc.	Hawaiian Electric Ind., Inc.	ONE Gas, Inc.
Alliant Energy Corporation	IDACORP Inc.	Pinnacle West Capital Corp.
Ameren Corporation	MGE Energy Inc.	PNM Resources, Inc.
Atmos Energy Corp.	New Jersey Resources Corp.	Portland General Electric Co.
Avista Corp.	NiSource, Inc.	Scana Corp.
CMS Energy Corp.	Northwest Natural Gas Co.	South Jersey Industries, Inc.
El Paso Electric Co.	NorthWestern Corp.	Spire, Inc.
Great Plains Energy, Inc.	OGE Energy Corp.	Vectren Corp.

The above peer companies were chosen by the Compensation Committee as the Compensation Peer Group after engaging Willis Towers Watson to do an extensive review. Approximately 75 percent of the above companies are a subset of the EEI Index, our Performance Peer Group, and were chosen because they were within our revenue range of 0.4x - 2.5x our size and market capitalization range of 0.25x - 4.0x our size. The EEI Index is comprised of pure electric utilities and combination gas and electric utilities. In addition, approximately 25 percent of the peer companies above were added to provide a mix of pure gas utilities.

The salary surveys are one of several factors the Committee uses in setting appropriate compensation levels. Other factors include Company performance, individual performance and experience, the level and nature of the executive's responsibilities, internal equity considerations and discussions with the CEO related to the other senior executive officers.

Components of Executive Compensation

The components of our executive compensation program consist of a base salary, a short-term incentive plan, and long-term incentives. In addition, we provide retirement and other benefits.

An important component of the executives' total compensation is derived from incentive compensation. Incentive compensation is intended to motivate and encourage our executives to drive performance and achieve superior results for our shareholders. The Committee periodically reviews information provided by the compensation consultant to determine the appropriate level and mix of incentive compensation. Actual income in the form of incentive compensation is realized by the executive as a result of achieving Company goals and overall stock performance. The Committee believes that a significant portion of total target compensation should be comprised of incentive compensation. In order to reward long-term growth while still encouraging short-term results, the Committee establishes incentive targets that emphasize long-term compensation at a greater level than short-term compensation.

The Committee annually reviews all components of each senior executive officer's compensation, including salary, short-term incentive, equity and other long-term incentive compensation values granted, and the current and potential value of the executive officer's total Black Hills Corporation equity holdings.

Base Salary. Base salaries for all officers are reviewed annually. We also adjust the base salary of our executives at the time of a promotion or change in job responsibility, as appropriate. Evaluation of 2018 base salary adjustments occurred in January 2018. The base salary component of each position was compared to the median of the market data provided by the compensation consultant. The market data indicated the salaries generally aligned with the utility industry median and below comparable general industry levels. The actual base salary of each officer was determined by the executive's performance, the experience level of the officer, the executive's current position in a market-based salary range, and internal pay relationships. Our CEO recommended, and our Board concurred, that our named executive officers not receive base salary merit increases in 2018 due to poor stock performance and other challenges in 2017.

	2017 Base Salary	2018 Base Salary
Emery, CEO	$820,000	$820,000
Kinzley, CFO	$381,000	$381,000
Evans, COO	$530,000	$530,000
Iverson, GC	$350,000	$350,000
Buchholz, CIO	$320,000	$320,000

Short-Term Incentive. Our Short-Term Incentive Plan is designed to recognize and reward the contributions of individual executives as well as the contributions that group performance makes to overall corporate success. The program's goal for our corporate officers is based on an earnings per share target in order to closely align interests with shareholders and to foster teamwork and cooperation within the officer team. The short-term incentive, after applicable tax withholding, is distributed to the officer in the form of 50 percent stock and 50 percent cash, unless the officer has met his or her stock ownership guideline, in which case he or she may elect to receive the total award in cash, after deductions and applicable tax withholding. Target award levels are established as a percentage of each participant's base salary. A target award is typically comparable to the average short-term incentive target award of the Performance Peer Group at the 50th percentile level. The actual payout will vary, based on attainment of pre-established performance goals, between 50 and 200 percent of the individual executive's short-term incentive target award level.

The Committee approves the target level for each officer in January, which applies to performance in the upcoming plan year. Target levels are derived in part from competitive data provided by the compensation consultant and in part by the Committee's judgment regarding internal equity, retention and an individual executive's expected contribution to the achievement of our strategic objectives. The target levels for the positions held by our Named Executive Officers are shown below:

Short-Term Incentive Target				
	2017		2018	
	% Amount	$ Amount	% Amount	$ Amount
Emery, CEO	110%	$902,000	110%	$902,000
Kinzley, CFO	60%	$228,600	60%	$228,600
Evans, COO	70%	$371,000	70%	$371,000
Iverson, GC	45%	$157,500	55%	$192,500
Buchholz, CIO	50%	$160,000	50%	$160,000

The threshold, target and maximum payout levels for our Named Executive Officers under the 2018 Short-Term Incentive Plan are shown in the Grants of Plan Based Awards in 2018 table on page 40, under the heading "Estimated Future Payouts Under Non-Equity Incentive Plan Awards."

Early in the first quarter, the Committee meets to establish the goals for the current plan year, to evaluate actual performance in relation to the prior year's targets and to approve the actual payment of awards related to the prior plan year. The Committee reserves the discretion to adjust any award, and will review and take into account individual performance, level of contribution, and the accomplishment of specific project goals that were initiated throughout the plan year.

The Committee selected an earnings per share goal based on ongoing operations, as adjusted, for 2018. This meets the objectives of the plan, including:

Aligns the interests of the plan participants and the shareholders with a corporate-wide component

Motivates employees and supports the corporate compensation philosophy

Provides an incentive reflective of core operating performance by adjusting for unique one-time events

Ensures "buy-in" from participants with easily understood metrics

Meets the performance objectives of the plan to achieve over-time, an average payout equal to market competitive levels

The Committee has defined earnings per share from ongoing operations, as adjusted, to be GAAP earnings per share adjusted for unique one-time non-budgeted events (similar to those items adjusted for when reporting non-GAAP earnings for external purposes), including external acquisition costs, impairments, transaction financing costs, unique tax transactions, and other items the Committee deems not reflective of ongoing operations and the value created for shareholders.

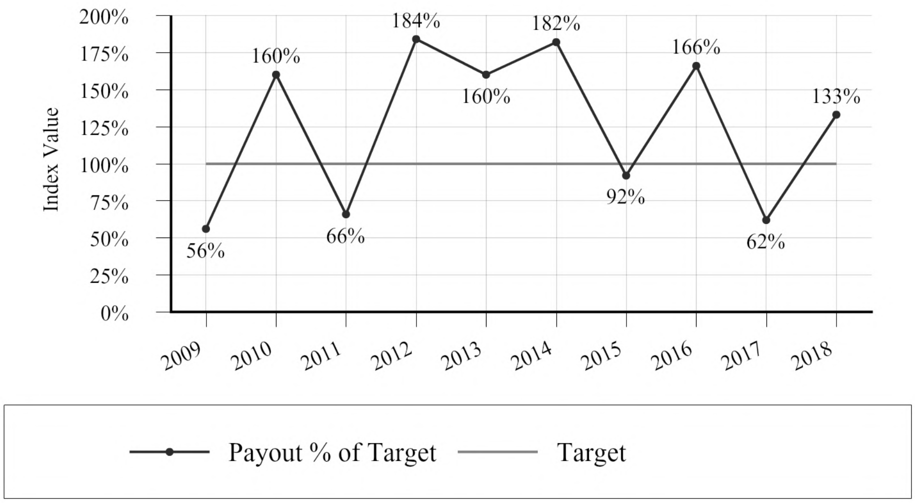
The Committee approved the goals for 2018 for the corporate officers as follows:

Threshold	Earnings Per Share from Ongoing Operations, as Adjusted	Payout % of Target
Minimum	$3.09	50%
Target	$3.43	100%
Maximum	$3.77	200%

On February 8, 2019, the Committee approved a payout of 133 percent of target under the 2018 Short-Term Incentive Plan based on the attainment of $3.54 earnings per share from ongoing operations, as adjusted, for incentive plan purposes. Earnings from ongoing operations, as adjusted, for incentive plan purposes were the same as earnings per share from continuing operations, as adjusted, reported externally to our investors (and reconciled to GAAP earnings per share in Appendix A). For 2018, actual adjustments included tax benefits related to legal entity restructuring at our gas utilities and Tax Cuts and Jobs Act related tax adjustments.

Payouts under the Short-Term Incentive Plan have varied over the last 10 years as shown in the graph below.

Short-Term Incentive Payout % of Target



Actual awards made to each of our Named Executive Officers under the Short-Term Incentive Plan for 2018 are included in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 38.

Long-Term Incentive. Long-term incentive compensation is comprised of grants made by the Committee under our 2015 Omnibus Incentive Plan. Long-term incentive compensation is intended to:

Promote corporate goals by linking the personal interests of participants to those of our shareholders

Provide participants with an incentive for excellence in individual performance

Promote teamwork among participants

Motivate, retain, and attract the services of participants who make significant contributions to our success by allowing participants to share in such success

Meet the performance objectives of the plan to achieve over-time, an average payout equal to market competitive levels

The Committee oversees the administration of the Omnibus Incentive Plans with full power and authority to determine when and to whom awards will be granted, along with the type, amount and other terms and conditions of each award. The long-term incentive compensation component is currently composed of performance shares and restricted stock. The Committee chose these components because linking executive compensation to stock price appreciation and total shareholder return is an effective way to align the interests of management with those of our shareholders. The Committee selected total shareholder return as the performance goal for the performance shares because it believes executive pay under a long-term, capital accumulation program should mirror our performance in shareholder return as compared to our Performance Peer Group of companies.

The value of long-term incentives awarded is based primarily on competitive market-based data presented by the compensation consultant to the Committee, the impact each position has on our shareholder return and internal pay relationships. The actual amount realized will vary from the awarded target amounts. The Committee approved the target long-term incentive compensation level for each officer in January 2018.

NEO Long-Term Incentive Target Compensation		
	2017	2018
Emery, CEO	$1,900,000	$1,900,000
Kinzley, CFO	$455,000	$480,000
Evans, COO	$800,000	$840,000
Iverson, GC	$350,000	$375,000
Buchholz, CIO	$230,000	$240,000

2018 NEO Long-Term Incentive Compensation as a Percentage of Base Salary					
	Emery, CEO	**Kinzley, CFO**	**Evans, COO**	**Iverson, GC**	**Buchholz, CIO**
% of Base Salary	232%	126%	158%	107%	75%

The variance in percentage of base salary for the long-term incentive value of our Named Executive Officers reflects our philosophy that certain officers should have more of their total compensation at risk because they hold positions that have a greater impact on our long-term results and is also consistent with market practice.

Performance shares are used to deliver 50 percent of the long-term incentive award amounts, with the remaining 50 percent delivered in the form of restricted stock. The actual shares of performance shares and restricted stock granted in 2018 are reflected in the tables in the *Performance Shares* and *Restricted Stock* sections that follow.

Performance Shares. Participants are awarded a target number of performance shares based upon the value of the individual performance share component approved by the Committee, divided by the Beginning Stock Price. The Beginning Stock Price is the average of the closing price of our common stock for the 20 trading days immediately preceding the beginning of the plan period. Entitlement to performance shares is based on our total shareholder return over designated performance periods, as measured against our Performance Peer Group. The final value of the performance shares is based upon the number of shares of common stock that are ultimately granted, based upon our performance in relation to the performance criteria.

The Committee, with the guidance of Willis Towers Watson, periodically conducts a review of the market competitiveness of our performance share plans. A summary of the performance criteria for each plan period is summarized in the table below.

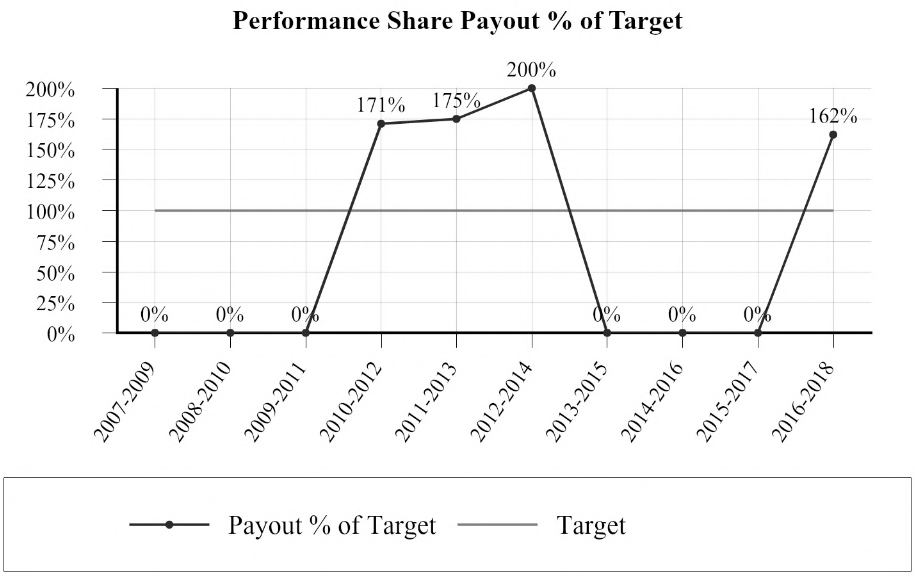
Performance Share Plans			
Percentile Ranking for Threshold Payout of 25% of Target Shares	Percentile Ranking for Target Payout of 100% of Target Shares	Percentile Ranking for Maximum Payout Level	Possible Payout Range of Target
25th percentile	50th percentile	90th percentile	0-200%

In addition, beginning with the 2017-2019 performance plan, our plans provide: (i) a threshold payout if relative TSR performance is below threshold but at 35 percent or higher; and (ii) the performance share plan payout is capped at 100 percent of target if TSR is negative. The additional provisions are intended to reduce the impact of one peer company's performance on the relative TSR plan, and also increase accountability and expectations related to the Company's performance.

The performance awards and dividend equivalents, if earned, are paid 50 percent in cash and 50 percent in common stock. All payroll deductions and applicable tax withholding related to the award are withheld from the cash portion. Performance share target grant values for new performance periods are approved in January of each year.

The Committee, with the guidance of Willis Towers Watson, periodically conducts a review of our Performance Peer Group to which we should be compared. Due to the extensive merger and acquisition activity in the industry and its contribution to relative performance volatility, the Committee chose to use the companies in the Edison Electric Index as the Performance Peer Group for financial performance tracking beginning with the 2017-2019 performance period.

Payouts under the Performance Share Plan have varied significantly over the last 10 years with either no payout or very high payouts, as shown in the graph below.



Each performance share period extends for three years. For the recently completed performance period, January 1, 2016 to December 31, 2018, our total shareholder return was 62 percent, which ranked at the 75th percentile of our Performance Peer Group, resulting in a payout at 162 percent of target.

Target shares for each of our Named Executive Officers for the outstanding performance periods are as follows:

	January 1, 2017 to December 31, 2019 Performance Period	January 1, 2018 to December 31, 2020 Performance Period
Emery, CEO	15,630	16,074
Kinzley, CFO	3,743	4,061
Evans, COO	6,581	7,107
Iverson, GC	2,879	3,173
Buchholz, CIO	1,892	2,030

Actual payouts, if any, will be determined based upon our total shareholder return for the plan period in comparison to our Performance Peer Group.

Restricted Stock. Restricted stock awarded as long-term incentives vest one-third each year over a three-year period, and automatically vest in their entirety upon death, disability or a change in control. Dividends are paid on the restricted stock. Unvested restricted stock is forfeited if an officer's employment is terminated for any reason other than death, disability or in the event of a change in control.

The number of shares of restricted stock awarded in 2018 for each of our Named Executive Officers is shown below and is included in the Grants of Plan Based Awards in 2018 table under the heading “All Other Stock Awards: Number of Shares of Stock or Units” and “Grant Date Fair Value of Stock Awards” on page 40.

	Long-Term Incentive
Emery, CEO	18,126
Kinzley, CFO	4,579
Evans, COO	8,014
Iverson, GC	3,578
Buchholz, CIO	2,290

Performance Evaluation

Role of Executive Officers in Compensation Decisions. The CEO annually reviews the performance of each of our executive officers. Based upon these performance reviews, market analysis conducted by compensation consultants and discussions with our Senior Vice President - Chief Human Resources Officer, the CEO recommends the compensation for this group of officers to the Committee.

Role of the Committee and Board in Setting Executive Compensation. The Committee reviews and establishes the Company’s financial targets and the CEO’s goals and objectives for the year. After the end of each year, the Committee evaluates the CEO’s performance in light of established goals and objectives, with input from the other independent directors. Based upon the Committee’s evaluation and recommendation, the independent directors of the Board set the CEO’s annual compensation, including salary, short-term incentive, long-term incentive and equity compensation.

The Committee reviews the CEO’s recommended compensation levels for our senior officers. The Committee may approve the CEO’s compensation recommendations for this group of officers or exercise its discretion in modifying any of the recommended compensation and award levels in its review and approval process. The Committee is required to approve all decisions regarding equity awards to our officers.

Compensation Arrangements Regarding Chief Executive Officer Transition

Effective December 31, 2018, Mr. Emery retired as Chief Executive Officer and Mr. Evans was appointed President and Chief Executive Officer, effective January 1, 2019. Mr. Emery continues to serve the Company as Executive Chairman until May 1, 2020. This leadership change was the result of a comprehensive, multi-year, board-led succession planning process.

The Compensation Committee engaged its compensation consultant, Willis Towers Watson, to conduct an extensive study on market compensation for an incoming Chief Executive Officer and the transition role of an Executive Chairman. The compensation consultant provided the Committee a Chief Executive Officer benchmarking report that regressed the proxy data of our Compensation Peer Group. The compensation consultant also advised the Committee that pay for a new Chief Executive Officer normally starts at the lower end of the competitive range and increases to the middle of the range within a few years, depending on performance and experience; and Executive Chairman compensation should take into account the change in roles and responsibilities and the level of support expected to be provided to the new Chief Executive Officer, while also maintaining stability and consistency at the board level during the transition. The Committee recommended and the Board approved the following compensation packages, effective January 1, 2019:

- As Executive Chairman, Mr. Emery will receive an annual salary equal to $1,300,000 in 2019, decreasing to an annual salary equal to $480,000, effective January 1, 2020 ($160,000 for the service period of January 1, 2020 to May 1, 2020). In addition, he will continue to receive all full-time employee and officer benefits and perquisites until his retirement as Executive Chairman on May 1, 2020. However, he will no longer participate in the Company’s Short-Term Incentive Plan or receive new awards under the Long-Term Incentive Plan. As Executive Chairman, Mr. Emery's stock ownership requirement will be a fixed number of shares in an amount that is substantially similar to when he was our Chairman and CEO.

- As President and Chief Executive Officer, Mr. Evans base salary will be $750,000. In addition, Mr. Evans will be eligible to receive an annual incentive based on 100 percent of his base salary in 2019 in accordance with the Company’s Short-Term Incentive Plan and $1,500,000 of target award value pursuant to the Company’s Long-Term Incentive Plan. These compensation actions result in a total target direct compensation level of $3,000,000 for Mr. Evans which is 91 percent of the market median.

STOCK OWNERSHIP GUIDELINES

The Committee has implemented stock ownership guidelines that apply to all officers based upon their level of responsibility. We believe it is important for our officers to hold a significant amount of our common stock to further align their performance with the interest of our shareholders. A “retention ratio” approach to stock ownership is incorporated into the guidelines. Officers are required to retain 100 percent of all shares owned, including shares awarded through our incentive plans (net of share withholding for taxes and, in the case of cashless stock option exercises, net of the exercise price and withholding for taxes) until specific ownership goals are achieved.

The guidelines are shown below.

Position	Stock Ownership Value as Multiple of Base Salary
CEO	6X
COO and CFO	4X
Other Senior Officers	3X

At least annually, the Compensation Committee reviews common stock ownership to confirm the officers have met or are progressing toward their stock ownership guidelines. Generally, an officer may not sell common stock unless he or she owns common stock in excess of 110 percent of the applicable stock ownership guideline. All of our Named Executive Officers have exceeded their stock ownership guidelines.

HEDGING POLICY

Our directors and executive officers are prohibited from hedging and pledging our stock or holding our stock in a margin account.

2018 BENEFITS

Retirement Benefits. We maintain a variety of employee benefit plans and programs in which our executive officers may participate. We believe it is important to provide post-employment benefits to our executive officers and the benefits we provide approximate retirement benefits paid by other employers to executives in similar positions. The Committee periodically reviews the benefits provided, with assistance from its compensation consultant, to maintain a market-based benefits package. None of our Named Executive Officers received any pension benefit payments in 2018.

Several years ago, we adopted a defined contribution plan design as our primary retirement plan and amended our Defined Benefit Pension Plan (“Pension Plan”) for all eligible employees to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Messrs. Emery and Buchholz are our only Named Executive Officers who met the age and service requirement allowing them to continue to accrue benefits under the Pension Plan. Employees who no longer accrue benefits under the Pension Plan now receive Company Retirement Contributions (“Retirement Contributions”) in the Retirement Savings Plan. The Retirement Contributions are an age and service points-based calculation.

The 401(k) Retirement Savings Plan is offered to all our eligible employees and we provide matching contributions for certain eligible participants. All of our Named Executive Officers are participants in the 401(k) Retirement Savings Plan and received matching contributions in 2018. The matching contributions and the Retirement Contributions are included as “All Other Compensation” in the Summary Compensation Table on page 38.

We also provide nonqualified plans to certain officers because of Internal Revenue Code limitations imposed on the qualified plans. The level of retirement benefits provided by the Pension Plan and Nonqualified Plans for each of our Named Executive Officers is reflected in the Pension Benefits for 2018 table on page 44. Our contributions to the Nonqualified Deferred Compensation Plan are included in the All Other Compensation column of the Summary Compensation Table on page 38 and the aggregate Nonqualified Deferred Compensation balance at December 31, 2018 is reported in the Nonqualified Deferred Compensation for 2018 table on page 47. These retirement benefits are explained in more detail in the accompanying narrative to the tables.

Other Personal Benefits. We provide the personal use of a Company vehicle, executive health services, and limited reimbursement of financial planning services as benefits to our executive officers and use of the corporate aircraft to go to outside board meetings for the CEO. The specific amount attributable to these benefits in 2018 is disclosed in the Summary Compensation Table on page 38. The Committee periodically reviews the other personal benefits provided to our executive officers and believes the current benefits are reasonable and consistent with our overall compensation program.

CHANGE IN CONTROL PAYMENTS

Our Named Executive Officers may also receive severance benefits in the event of a change in control. We have no employment agreements with our Named Executive Officers. However, change in control agreements are common among our Compensation Peer Group and the Committee and our Board of Directors believe providing these agreements to our corporate officers protects our shareholder interests in the event of a change in control by helping assure management focus and continuity. Our change in control agreements have expiration dates and our Board of Directors conducts a thorough review of the change in control agreements at each renewal period. Our current change in control agreements expire November 15, 2019. In general, our change in control agreements provide a severance payment of up to 2.99 times average compensation for Mr. Emery, and up to two times average compensation for the other Named Executive Officers. The change in control agreements do not provide for excise tax gross-ups and contain a “double trigger,” providing benefits in association with:

(1) a change in control, and

(2) (i) a termination of employment other than by death, disability or by us for cause, or

(ii) a termination by the employee for good reason.

See the Potential Payments upon Termination or Change in Control table on page 49 and the accompanying narrative for more information regarding our change in control agreements and estimated payments associated with a change in control.

TAX AND ACCOUNTING IMPLICATIONS

Section 162(m) of the U.S. Internal Revenue Code of 1986, as amended, limits the tax deductibility by a corporation of compensation in excess of $1 million paid to certain of its officers. Section 162(m) as in effect prior to the enactment of tax reform legislation in December 2017 generally disallowed a tax deduction to public companies for compensation of more than $1 million paid in any taxable year to each “covered employee,” consisting of the CEO and the three other highest paid executive officers employed at the end of the year (other than the CFO). Performance-based compensation was exempt from this deduction limitation if the Company met specified requirements set forth in the Code and applicable Treasury Regulations.

For years beginning January 1, 2018, there is no exception from the deduction limit under Section 162(m) for performance based compensation unless it qualifies for transitional relief applicable to certain binding, written performance-based compensation arrangements that were in place as of November 2, 2017, and were not materially modified after that date. In addition, "covered employees" also include any person who served as CEO or CFO at any time during a taxable year, as well as any person who was ever identified as a covered employee in 2017 or any subsequent year. The Committee continues to believe that shareholder interests are best served if its discretion and flexibility in structuring and awarding compensation is not restricted, even though some past and/or future compensation awards result in non-deductible compensation expenses to the Company. The Committee’s ability to continue to provide a competitive compensation package to attract, motivate and retain the Company’s most senior executives is considered critical to the Company’s success and to advancing the interests of its shareholders.

CLAWBACK POLICY

We have a policy that if an accounting restatement occurs after incentive payments have been made, due to the results of misconduct associated with financial reporting, the Committee will seek repayment of the incentive compensation from our CEO and CFO, and the Committee has the discretion to request repayment of incentive compensation from our other officers, taking into consideration the individual roles and responsibilities prompting the restatement.

In addition, our award agreements for restricted stock and target performance shares include clawback provisions whereby the participant may be required to repay all income or gains previously realized in respect of such awards if his or her employment is terminated for cause, or if, within one year following termination of employment, the Board determines that the participant engaged in conduct prior to his or her termination that would have constituted the basis for a termination of employment for cause.

REPORT OF THE COMPENSATION COMMITTEE

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to our Board of Directors that the Compensation Discussion and Analysis be included in this proxy statement.

THE COMPENSATION COMMITTEE

Michael H. Madison, Chair
Rebecca B. Roberts
Teresa A. Taylor
Thomas J. Zeller

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the years ended December 31, 2018, 2017 and 2016. We have no employment agreements with our Named Executive Officers.

Name and Principal Position	Year	Salary	Stock Awards[2]	Non-Equity Incentive Plan Compensation[3]	Changes in Pension Value and Nonqualified Deferred Compensation Earnings [4]	All Other Compensation[5]	Total
David R. Emery[1]	2018	$820,000	$1,943,679	$1,196,503	$523,260	$140,256	$4,623,698
Executive Chairman (former Chairman and CEO)	2017	$812,000	$1,942,843	$560,232	$2,155,930	$92,930	$5,563,935
	2016	$767,000	$1,926,358	$1,283,218	$1,061,157	$104,751	$5,142,484
Richard W. Kinzley	2018	$381,000	$491,036	$303,238	$—	$195,249	$1,370,523
Sr. Vice President and Chief Financial Officer	2017	$378,000	$465,256	$141,983	$36,599	$250,572	$1,272,410
	2016	$357,500	$514,297	$362,027	$23,493	$174,154	$1,431,471
Linden R. Evans[1]	2018	$530,000	$859,369	$492,132	$—	$306,330	$2,187,831
President and Chief Executive Officer (former President and Chief Operating Officer)	2017	$523,333	$818,045	$230,428	$59,631	$385,948	$2,017,385
	2016	$485,833	$773,875	$529,411	$37,711	$299,611	$2,126,441
Brian G. Iverson	2018	$350,000	$383,678	$255,351	$—	$123,852	$1,112,881
Sr. Vice President and General Counsel	2017	$346,667	$357,856	$97,823	$17,736	$145,405	$965,487
	2016	$325,000	$422,433	$246,837	$11,890	$111,429	$1,117,589
Scott A. Buchholz	2018	$320,000	$245,514	$212,240	$38,765	$111,285	$927,804
Sr. Vice President and Chief Information Officer	2017	$317,500	$235,193	$99,376	$366,235	$133,407	$1,151,711
	2016	$302,500	$370,033	$228,137	$366,662	$112,969	$1,380,301

(1) Mr. Emery retired as our Chairman and Chief Executive Officer, effective December 31, 2018. He continues his full-time employment with the Company as Executive Chairman of the Board. Mr. Evans was named President and Chief Executive Officer effective January 1, 2019. Previously, he was President and Chief Operating Officer.

(2) Stock Awards represent the grant date fair value related to restricted stock and performance shares that have been granted as a component of long-term incentive compensation and for 2016, include special achievement awards associated with the acquisition of SourceGas. The grant date fair value is computed in accordance with the provisions of accounting standards for stock compensation. Assumptions used in the calculation of these amounts are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2018.

(3) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2018 awards on February 8, 2019 and the awards were paid on March 8, 2019.

(4) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective years. These benefits have been valued using the assumptions disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2018. Because these assumptions sometimes change between measurement dates, the change in value reflects not only the change in value due to additional benefits earned during the period and the passage of time but also reflects the change in value caused by changes in the underlying actuarial assumptions. This has created significant volatility in the last three years with a large decrease in 2018 and a large increase in 2017 primarily related to the change in discount rates used to calculate the present value of these benefits. A value of zero is shown in the Summary Compensation Table for certain officers in 2018 because the SEC does not allow a negative number to be disclosed in the table.

The Pension Plan and PRB were frozen effective January 1, 2010 for participants who did not satisfy the age 45 and 10 years of service eligibility. Messrs. Kinzley, Evans and Iverson did not meet the eligibility choice criteria and their Defined Pension and PRB benefits were frozen.

The PEP is offered through the Grandfathered Pension Equalization Plan ("Grandfathered PEP") and 2005 Pension Equalization Plan ("2005 PEP"). Mr. Emery is the only participant in the Grandfathered PEP and 2005 PEP. Messrs. Kinzley, Evans, Iverson and Buchholz are not participants in these plans; instead they receive employer contributions into a Nonqualified Deferred Compensation Plan ("NQDC"). The NQDC employer contributions are reported in the All Other Compensation column.

No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The change in value attributed to each Named Executive Officer from each plan is shown in the table below.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2018	($33,492)	$377,323	$179,429	$523,260
	2017	$235,056	$1,281,606	$639,268	$2,155,930
	2016	$85,671	$641,790	$333,696	$1,061,157
Richard W. Kinzley	2018	($23,542)	($1,394)	$—	($24,936)
	2017	$34,487	$2,112	$—	$36,599
	2016	$22,312	$1,181	$—	$23,493
Linden R. Evans	2018	($19,607)	($15,074)	$—	($34,681)
	2017	$33,178	$26,453	$—	$59,631
	2016	$22,258	$15,453	$—	$37,711
Brian G. Iverson	2018	($10,523)	$—	$—	($10,523)
	2017	$17,736	$—	$—	$17,736
	2016	$11,890	$—	$—	$11,890
Scott A. Buchholz	2018	($42,215)	$80,980	$—	$38,765
	2017	$226,019	$140,216	$—	$366,235
	2016	$161,952	$204,710	$—	$366,662

(5) All Other Compensation includes amounts allocated under the 401(k) match, defined contributions, NQDC contributions, dividends received on restricted stock and unvested restricted stock units and other personal benefits. The Other Personal Benefits column reflects the personal use of a Company vehicle, executive health, and financial planning services for each NEO. For Mr. Emery, Other Personal Benefits also includes use of the corporate aircraft to travel to outside board meetings. The aggregate incremental cost for such aircraft usage in 2018 was $39,196.

	Year	401(k) Match	Defined Contributions	NQDC Contributions	Dividends on Restricted Stock	Other Personal Benefits	Total Other Compensation
David R. Emery	2018	$16,500	$—	$—	$68,033	$55,723	$140,256
Richard W. Kinzley	2018	$16,500	$21,909	$126,240	$17,991	$12,609	$195,249
Linden R. Evans	2018	$16,500	$22,000	$220,046	$30,112	$17,672	$306,330
Brian G. Iverson	2018	$16,500	$17,620	$60,021	$14,083	$15,628	$123,852
Scott A. Buchholz	2018	$16,500	$—	$67,375	$10,030	$17,380	$111,285

GRANTS OF PLAN BASED AWARDS IN 2018(1)

Name	Grant Date	Date of Compensation Committee Action	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(2) Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards(3) Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units(4) (#)	Grant Date Fair Value of Stock Awards(5) ($)
David R. Emery			$451,000	$902,000	$1,804,000					
	1/30/18	1/30/18				4,019	16,074	32,148		$993,695
	2/5/18	1/30/18							18,126	$949,984
Richard W. Kinzley			$114,300	$228,600	$457,200					
	1/30/18	1/30/18				1,015	4,061	8,122		$251,051
	2/5/18	1/30/18							4,579	$239,985
Linden R. Evans			$185,500	$371,000	$742,000					
	1/30/18	1/30/18				1,777	7,107	14,214		$439,355
	2/5/18	1/30/18							8,014	$420,014
Brian G. Iverson			$96,250	$192,500	$385,000					
	1/30/18	1/30/18				793	3,173	6,346		$196,155
	2/5/18	1/30/18							3,578	$187,523
Scott A. Buchholz			$80,000	$160,000	$320,000					
	1/30/18	1/30/18				508	2,030	4,060		$125,495
	2/5/18	1/30/18							2,290	$120,019

(1) No stock options were granted to our Named Executive Officers in 2018.

(2) The columns under “Estimated Future Payouts Under Non-Equity Incentive Plan Awards” show the range of payouts for 2018 performance under our Short-Term Incentive Plan as described in the Compensation Discussion and Analysis under the section titled “Short-Term Incentive” on page 29. If the performance criteria are met, payouts can range from 50 percent of target at the threshold level to 200 percent of target at the maximum level. The 2019 bonus payment for 2018 performance has been made based on achieving the criteria described in the Compensation Discussion and Analysis, at 133 percent of target, and is shown in the Summary Compensation Table on page 38 in the column titled “Non-Equity Incentive Plan Compensation.”

(3) The columns under “Estimated Future Payouts Under Equity Incentive Plan Awards” show the range of payouts (in shares of stock) for the January 1, 2018 to December 31, 2020 performance period as described in the Compensation Discussion and Analysis under the section titled “Long-Term Incentive – Performance Shares” on page 31. If the performance criteria are met, payouts can range from 25 percent of target to 200 percent of target. If a participant retires, suffers a disability or dies during the performance period, the participant or the participant’s estate is entitled to that portion of the number of performance shares as such participant would have been entitled to had he or she remained employed, prorated for the number of months served. Performance shares are forfeited if employment is terminated for any other reason. During the performance period, dividends and other distributions paid with respect to the shares of common stock accrue for the benefit of the participant and are paid out at the end of the performance period.

(4) The column “All Other Stock Awards” reflects the number of shares of restricted stock granted on February 5, 2018 under our 2015 Omnibus Incentive Plan. The restricted stock vests one-third each year over a three-year period, and automatically vests upon death, disability or a change in control. Unvested restricted stock is forfeited if employment is terminated for any other reason. Dividends are paid on the restricted stock and the dividends that were paid in 2018 are included in the column titled “All Other Compensation” in the Summary Compensation Table on page 38.

(5) The column “Grant Date Fair Value of Stock Awards” reflects the grant date fair value of each equity award computed in accordance with the provisions of accounting standards for stock compensation. The grant date fair value for the performance shares was $61.82 per share and was calculated using a Monte Carlo simulation model. Assumptions used in the calculation are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2018. The grant date fair value for the restricted stock was $52.41 per share for the February 5, 2018 grant, which was the market value of our common stock on the date of grant as reported on the NYSE.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2018[1]

Name	Stock Awards			
	Number of Shares or Units of Stock That Have Not Vested[2] (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[2] (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
David R. Emery	35,250	$2,212,995	68,237	$4,357,910
Richard W. Kinzley	9,322	$585,235	15,091	$961,285
Linden R. Evans	15,602	$979,494	25,915	$1,650,120
Brian G. Iverson	7,297	$458,106	12,296	$783,952
Scott A. Buchholz	5,197	$326,268	8,756	$559,430

(1) There were no stock options outstanding at December 31, 2018 for our Named Executive Officers.

(2) Vesting dates for restricted stock and performance shares are shown in the table below. The performance shares shown with a vesting date of December 31, 2018, are the actual equivalent shares, including dividend equivalents, earned for the performance period ended December 31, 2018. On January 29, 2019, the Compensation Committee confirmed that the performance criteria were met and there would be a 162 percent payout of target. The performance shares with a vesting date of December 31, 2019 and a vesting date of December 31, 2020 are shown at the threshold and maximum payout levels, respectively, based upon performance as of December 31, 2018.

Name	Unvested Restricted Stock		Unvested and Unearned Performance Shares	
	# of Shares	Vesting Date	# of Shares	Vesting Date
David R. Emery	5,143	02/03/19	32,181	12/31/18
	6,837	02/04/19	3,908	12/31/19
	6,042	02/05/19	32,148	12/31/20
	5,144	02/03/20		
	6,042	02/05/20		
	6,042	02/05/21		
Richard W. Kinzley	1,232	02/03/19	6,033	12/31/18
	2,279	02/04/19	936	12/31/19
	1,526	02/05/19	8,122	12/31/20
	1,232	02/03/20		
	1,526	02/05/20		
	1,527	02/05/21		
Linden R. Evans	2,166	02/03/19	10,056	12/31/18
	3,256	02/04/19	1,645	12/31/19
	2,671	02/05/19	14,214	12/31/20
	2,166	02/03/20		
	2,671	02/05/20		
	2,672	02/05/21		
Brian G. Iverson	947	02/03/19	5,230	12/31/18
	1,824	02/04/19	720	12/31/19
	1,192	02/05/19	6,346	12/31/20
	948	02/03/20		
	1,193	02/05/20		
	1,193	02/05/21		
Scott A. Buchholz	623	02/03/19	4,223	12/31/18
	1,661	02/04/19	473	12/31/19
	763	02/05/19	4,060	12/31/20
	623	02/03/20		
	763	02/05/20		
	764	02/05/21		

OPTION EXERCISES AND STOCK VESTED DURING 2018[1]

Name	Stock Awards[2]	
	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
David R. Emery	16,603	$894,902
Richard W. Kinzley	4,336	$233,710
Linden R. Evans	6,908	$372,341
Brian G. Iverson	3,497	$188,488
Scott A. Buchholz	2,944	$158,682

(1) There were no stock options exercised during 2018.

(2) Reflects restricted stock that vested in 2018, as there was no payout in 2018 of performance shares for the 2015-2017 performance period.

PENSION BENEFITS FOR 2018

Several years ago, we adopted a defined contribution plan design as our primary retirement plan and amended our Pension Plan and Nonqualified Pension Plans for all eligible employees to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Employees eligible to elect continued participation were those employees who were at least 45 years old and had at least 10 years of eligible service with us as of January 1, 2010. Messrs. Emery and Buchholz were our only Named Executive Officers who met the age and service requirement and continue to accrue benefits under the Pension Plan and the Pension Restoration Plan. Benefits under the Pension Plan and Pension Restoration Plan were frozen for Messrs. Kinzley, Evans and Iverson. In addition, Mr. Emery received supplemental pension benefits under the Grandfathered Pension Equalization Plan, which was frozen effective December 31, 2004, and the 2005 Pension Equalization Plan. None of our Named Executive Officers received any pension benefit payments during the fiscal year ended December 31, 2018.

The present value accumulated by each Named Executive Officer from each plan is shown in the table below:

Name	Plan Name	Number of Years of Credited Service[(1)] (#)	Present Value of Accumulated Benefit[(2)] ($)
David R. Emery	Pension Plan	29.33	$1,115,504
	Pension Restoration Benefit	29.33	$7,054,613
	Grandfathered Pension Equalization Plan	23.00	$799,690
	2005 Pension Equalization Plan	23.00	$3,758,329
Richard W. Kinzley	Pension Plan	10.50	$225,455
	Pension Restoration Benefit	10.50	$13,860
Linden R. Evans	Pension Plan	8.58	$255,960
	Pension Restoration Benefit	8.58	$204,825
Brian G. Iverson	Pension Plan	5.83	$136,310
Scott A. Buchholz	Pension Plan	39.17	$1,444,793
	Pension Restoration Plan	39.17	$1,219,241

(1) The number of years of credited service represents the number of years used in determining the benefit for each plan. The Pension Equalization Plans are not directly tied to service but rather the number of years of participation in the plan.

(2) The present value of accumulated benefits was calculated assuming the participants will work until retirement, benefits commence at age 62 and using the discount rate, mortality rate and assumed payment form assumptions consistent with those disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2018.

DEFINED BENEFIT PENSION PLAN

Our Pension Plan is a qualified pension plan in which all of our Named Executive Officers are included. As discussed above, several years ago we amended our Pension Plan to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Messrs. Emery and Buchholz were the only Named Executive Officers who met the age and service requirement and elected to continue with the existing plan.

The Pension Plan provides benefits at retirement based on length of employment service and average compensation levels during the highest five consecutive years of the last ten years of service. For purposes of the benefit calculation, earnings include wages and other cash compensation received from us, including any bonus, commission, unused paid time off or incentive compensation. It also includes any elective before-tax contributions made by the employee to a Company-sponsored cafeteria plan or 401(k) plan. However, it does not include any expense reimbursements, taxable fringe benefits, moving expenses or moving/relocation allowances, nonqualified deferred compensation, non-cash incentives, stock options and any payments of long-term incentive compensation such as restricted stock or payments under performance share plans. The Internal Revenue Code places maximum limitations on the amount of compensation that may be recognized when determining benefits of qualified pension plans. In 2018, the maximum amount of compensation that could be recognized when determining compensation was $275,000 (called "covered compensation"). Our employees do not contribute to the plan. The amount of the annual contribution by us to the plan is based on an actuarial determination.

The benefit formula for the Named Executive Officers in the plan is the sum of (a) and (b) below.

(a) Credited Service after January 31, 2000

0.9% of average earnings (up to covered compensation), multiplied by credited service after January 31, 2000 minus the number of years of credited service before January 31, 2000	Plus	1.3% of average earnings in excess of covered compensation, multiplied by credited service after January 31, 2000 minus the number of years of credited service before January 31, 2000

Plus

(b) Credited Service before January 31, 2000

1.2% of average earnings (up to covered compensation), multiplied by credited service before January 31, 2000	Plus	1.6% of average earnings in excess of covered compensation, multiplied by credited service before January 31, 2000

Pension benefits are not reduced for social security benefits. The Internal Revenue Code places maximum limitations on annual benefit amounts that can be paid under qualified pension plans. In 2018, the maximum benefit payable under qualified pension plans was $220,000. Accrued benefits become 100 percent vested after an employee completes five years of service.

Normal retirement is defined as age 65 under the plan. However, a participant may retire and begin taking unreduced benefits at age 62 with five years of service. Participants who have completed at least five years of credited service can retire and receive defined benefit pension benefits as early as age 55. However, the retirement benefit will be reduced by five percent for each year of retirement before age 62. Messrs. Emery, Evans, Iverson and Buchholz are currently age 55 or older and are entitled to early retirement benefits under this provision.

PENSION EQUALIZATION PLANS AND PENSION RESTORATION BENEFIT

We also have a Grandfathered Pension Equalization Plan, a 2005 Pension Equalization Plan and a Pension Restoration Benefit. These are nonqualified supplemental plans, in which benefits are not tax deductible until paid. The plans are designed to provide the higher paid executive employee a retirement benefit which, when added to social security benefits and the pension to be received under the Pension Plan, will approximate retirement benefits being paid by other employers to their employees in similar executive positions. The employee's pension from the qualified Pension Plan is limited by the Internal Revenue Code. The 2018 pension limit was set at $220,000 annually and the compensation taken into account in determining contributions and benefits could not exceed $275,000 and could not include nonqualified deferred compensation. The amount of deferred compensation paid under nonqualified plans is not subject to these limits.

As a result of the change in the Pension Plan discussed above, the benefits for certain officers (including Messrs. Kinzley, Evans, and Iverson) under the Nonqualified Pension Plans were significantly reduced because the nonqualified benefit calculations were linked to the benefits earned in the Pension Plan. The Compensation Committee amended the Nonqualified Deferred Compensation Plan to provide non-elective nonqualified restoration benefits to those affected officers who were not eligible to continue accruing benefits under the Pension Plan and Nonqualified Pension Plans.

Grandfathered Pension Equalization Plan and 2005 Pension Equalization Plan. The Grandfathered Pension Equalization Plan provides the pension equalization benefits to each participant who had earned and vested benefits before January 1, 2005, and is not subject to the provisions of Section 409A of the Internal Revenue Code. The 2005 Pension Equalization Plan provides the pension equalization benefits to each participant that were earned and vested on or after January 1, 2005, and is subject to the provisions of Section 409A.

These plans have been frozen to new participants since 2002. Mr. Emery is a fully vested participant in the Grandfathered and 2005 Pension Equalization Plans. Messrs. Kinzley, Evans, Iverson, and Buchholz are not participants in these plans.

The annual benefit for Mr. Emery is 30 percent of his average earnings multiplied by the vesting percentage. Average earnings are normally an employee's average earnings for the five highest consecutive full years of employment during the ten full years of employment immediately preceding the year of calculation. The annual benefit is paid on a monthly basis for 15 years and, if deceased, to the employee's designated beneficiary or estate, commencing at the earliest of death or when the employee is both retired and 62 years of age or more. A participant with vested benefits who is 55 years of age or older and who is no longer our employee may elect to be paid benefits beginning at age 55 or older, subject to a discount, ranging from 60.3 percent of the benefit payable at age 55 to 93 percent of the benefit payable at age 61.

Pension Restoration Benefit. In the event that at the time of a participant's retirement, the participant's salary level exceeds the qualified Pension Plan annual compensation limitation ($275,000 in 2018) or includes nonqualified deferred compensation, then the participant will receive an additional benefit, called a "Pension Restoration Benefit," which is measured by the difference between (i) the monthly benefit that would have been provided to the participant under the Pension Plan as if there were no annual compensation limitation and no exclusion on nonqualified deferred compensation, and (ii) the monthly benefit to be provided to the participant under the Pension Plan. The Pension Restoration Benefit applies to all of the Named Executive Officers that have a pension benefit.

NONQUALIFIED DEFERRED COMPENSATION FOR 2018

We have a Nonqualified Deferred Compensation Plan for a select group of management or highly compensated employees. Eligibility to participate in the plan is determined by the Compensation Committee and primarily consists of only corporate officers.

A summary of the activity in the plan and the aggregate balance as of December 31, 2018 for our Named Executive Officers is shown in the following table. Our Named Executive Officers received no withdrawals or distributions from the plan in 2018.

Name	Executive Contributions	Company Contributions in Last Fiscal Year(1)	Aggregate Earnings in Last Fiscal Year(2)	Aggregate Balance at Last Fiscal Year End(3)
David R. Emery	$—	$—	$—	$—
Richard W. Kinzley	$—	$126,240	($105,883)	$1,085,906
Linden R. Evans	$—	$220,046	($225,575)	$2,451,696
Brian G. Iverson	$—	$60,021	($32,641)	$405,304
Scott A. Buchholz	$—	$67,375	($37,372)	$741,266

(1) Our contributions represent non-elective Supplemental Matching and Retirement Contributions and Supplemental Target Contributions (defined in the paragraph below) and are included in the All Other Compensation column of the Summary Compensation Table. The value attributed from each contribution type to each Named Executive Officer in 2018 is shown in the table below:

Name	Supplemental Matching Contribution	Supplemental Retirement Contribution	Supplemental Target Contribution	Total Company Contributions
David R. Emery	$—	$—	$—	$—
Richard W. Kinzley	$14,879	$19,839	$91,522	$126,240
Linden R. Evans	$29,126	$38,834	$152,086	$220,046
Brian G. Iverson	$10,369	$13,826	$35,826	$60,021
Scott A. Buchholz	$8,662	$—	$58,713	$67,375

(2) Because amounts included in this column do not include above-market or preferential earnings, none of these amounts are included in the “Change in Pension Value and Nonqualified Deferred Compensation Earnings” column of the Summary Compensation Table.

(3) Messrs. Kinzley’s, Evans’, Iverson’s and Buchholz’s aggregate balances at December 31, 2018 include $429,837, $743,829, $203,675 and $228,485, respectively, which are included in the Summary Compensation Table as 2018, 2017 and 2016 compensation.

Eligible employees may elect to defer up to 50 percent of their base salary and up to 100 percent of their Short-Term Incentive Plan award. In addition, the Nonqualified Deferred Compensation Plan was amended to provide certain officers whose Pension Plan benefit and Nonqualified Pension Plans’ benefits were frozen with non-elective supplemental matching contributions equal to 6 percent of eligible compensation in excess of the Internal Revenue Code limit plus matching contributions, if any, lost under the 401(k) Retirement Savings Plan due to nondiscrimination test results and provides non-elective supplemental age and service points-based contributions that cannot be made to the 401(k) Retirement Savings Plan due to the Internal Revenue Code limit (“Supplemental Matching and Retirement Contributions”). It also provides supplemental target contributions equal to a percentage of compensation that may differ by executive, based on the executive’s current age and length of service with us, as determined by the plans’ actuary (“Supplemental Target Contributions”). Messrs. Kinzley, Evans, Iverson and Buchholz received Supplemental Target Contributions of 17.5 percent, 20 percent, 8 percent and 14 percent, respectively.

The deferrals are deposited into hypothetical investment accounts where the participants may direct the investment of the deferrals as allowed by the plan. The investment options are the same as those offered to all employees in the 401(k) Retirement Savings Plan except for a fixed rate option, which was set at 3.12 percent in 2018. Investment earnings are credited to the participants’ accounts. Upon retirement, we will distribute the account balance to the participant according to the distribution election filed with the Compensation Committee. The participants may elect either a lump sum payment to be paid within 30 days of retirement (requires a six-month deferral for benefits not vested as of December 31, 2004), or annual or monthly installments over a period of years designated by the participant, but not to exceed 15 years. As of January 1, 2019, Messrs. Kinzley, Evans, Iverson and Buchholz are 100 percent vested in the plan.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The following table describes the potential payments and benefits under our compensation and benefit plans and arrangements to which our Named Executive Officers would be entitled upon termination of employment. Except for (i) certain terminations following a change in control ("CIC"), as described below, (ii) pro-rata payout of incentive compensation and the acceleration of vesting of equity awards upon retirement, death or disability, and (iii) certain pension and nonqualified deferred compensation arrangements described under Pension Benefits for 2018 and Nonqualified Deferred Compensation for 2018 above, there are no agreements, arrangements or plans that entitle the Named Executive Officers to severance, perquisites, or other enhanced benefits upon termination of their employment. Any agreements to provide other payments or benefits to a terminating executive officer would be in the discretion of the Compensation Committee.

The amounts shown below assume that such termination was effective as of December 31, 2018, and thus include estimates of the amounts that would be paid out to our Named Executive Officers upon their termination. The table does not include amounts such as base salary, short-term incentives and stock awards that the Named Executive Officers earned due to employment through December 31, 2018 and distributions of vested benefits such as those described under Pension Benefits for 2018 and Nonqualified Deferred Compensation for 2018. The table also does not include a value for outplacement services because this would be a de minimis amount. The actual amounts to be paid can only be determined at the time of such Named Executive Officer's separation from us.

	Cash Severance Payment	Incremental Retirement Benefit (present value)(2)	Continuation of Medical/ Welfare Benefits (present value)(3)	Acceleration of Equity Awards(4)	Total Benefits
David R. Emery					
• Retirement	—	—	—	$765,539	$765,539
• Death or disability	—	—	—	$2,978,534	$2,978,534
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$2,881,913	$2,881,913
• Involuntary or good reason termination after CIC(1)	$5,148,780	$773,200	$112,300	$2,881,913	$8,916,193
Richard W. Kinzley					
• Retirement	—	—	—	$188,921	$188,921
• Death or disability	—	—	—	$774,156	$774,156
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$745,425	$745,425
• Involuntary or good reason termination after CIC(1)	$1,219,200	$384,048	$83,500	$745,425	$2,432,173
Linden R. Evans					
• Retirement	—	—	—	$331,289	$331,289
• Death or disability	—	—	—	$1,310,782	$1,310,782
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$1,261,141	$1,261,141
• Involuntary or good reason termination after CIC(1)	$1,802,000	$612,680	$58,400	$1,261,141	$3,734,221
Brian G. Iverson					
• Retirement	—	—	—	$146,618	$146,618
• Death or disability	—	—	—	$604,723	$604,723
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$581,318	$581,318
• Involuntary or good reason termination after CIC(1)	$1,085,000	$238,700	$52,600	$581,318	$1,957,618
Scott A. Buchholz					
• Retirement	—	—	—	$94,894	$94,894
• Death or disability	—	—	—	$421,162	$421,162
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$407,240	$407,240
• Involuntary or good reason termination after CIC(1)	$960,000	$354,300	$53,800	$407,240	$1,775,340

(1) The amounts reflected for involuntary or good reason termination after a change in control include the benefits a Named Executive Officer would receive in the event of a change in control as a sole event without the involuntary or good reason termination.

(2) Assumes that in the event of a change in control, Mr. Emery will receive an additional three years of credited and vesting service and the other Named Executive Officers will receive an additional two years of credited and vesting service towards the benefit accrual under their applicable retirement plans. For Mr. Emery, this would be the Pension Plan and Nonqualified Pension Plans. For Messrs. Kinzley, Evans, Iverson and Buchholz, this would be the Retirement Contributions and Nonqualified Deferred Compensation contributions. In addition, Mr. Buchholz would also have a Pension Restoration Contribution. The benefits will immediately vest and payments will commence at the earliest eligible date unless the executive has elected a later date for the nonqualified plans. This is age 55 for Mr. Kinzley. Because Messrs. Emery, Evans, Iverson and Buchholz are age 55 or older, they are already retiree eligible.

(3) Welfare benefits include medical coverage, dental coverage, life insurance, short-term disability coverage and long-term disability coverage. The calculation assumes that the Named Executive Officer does not take employment with another employer following termination, elects continued welfare benefits until age 55 or, if later, the end of the two year benefit continuation period (three years for Mr. Emery) and elects retiree medical benefits thereafter. Retirement is assumed to occur at the earliest eligible date.

(4) In the event of death or disability, the acceleration of equity awards represents the acceleration of unvested restricted stock and the assumed payout of the pro-rata share of the performance shares for the January 1, 2017 to December 31, 2019 and January 1, 2018 to December 31, 2020 performance periods. In the event of retirement, all unvested restricted stock is forfeited and the acceleration of equity awards represents only the pro-rata share of the performance shares. We assumed a 48 percent payout of the performance shares for the January 1, 2017 to December 31, 2019 performance period and a 118 percent payout of target for the January 1, 2018 to December 31, 2020 performance period based on our Monte Carlo valuations at December 31, 2018.

In the event of a change in control or an involuntary or good reason termination after a change in control, the acceleration of equity awards represents the acceleration of unvested restricted stock and the payout of the pro-rata share of the performance shares calculated as if the performance period ended on December 31, 2018 for the January 1, 2017 to December 31, 2019 and January 1, 2018 to December 31, 2020 performance periods.

The valuation of the restricted stock was based upon the closing price of our common stock on December 31, 2018, and the valuation of the performance shares was based on the average closing price of our common stock for the last 20 trading days of 2018. Actual amounts to be paid out at the time of separation from us may vary significantly based upon the market value of our common stock at that time.

Payments Made Upon Termination. Regardless of the manner in which a Named Executive Officer's employment terminates, he or his beneficiaries may be entitled to receive amounts earned during his term of employment. These include:

- accrued salary and unused vacation pay;
- amounts vested under the Pension Plan and Nonqualified Pension Plans;
- amounts vested under the Nonqualified Deferred Compensation Plan; and
- amounts vested under the 401(k) Retirement Savings Plan.

Payments Made Upon Retirement. In the event of retirement of a Named Executive Officer, in addition to the items identified above, he will also receive the benefit of the following:

- a pro-rata share of the performance shares for each outstanding performance period upon completion of the performance period; and
- a pro-rata share of the actual payout under the Short-Term Incentive Plan upon completion of the incentive period.

Payments Made Upon Death or Disability. In the event of death or disability of a Named Executive Officer, in addition to the items identified above for payments made upon termination, he will also receive the benefit of the following:

- accelerated vesting of restricted stock and restricted stock units;
- a pro-rata share of the performance shares for each outstanding performance period upon completion of the performance period; and
- a pro-rata share of the actual payout under the Short-Term Incentive Plan upon completion of the incentive period.

Payments Made Upon a Change in Control. Our Named Executive Officers have change in control agreements that terminate November 15, 2019. The renewal of the change in control agreements is at the discretion of the Compensation Committee and the Board of Directors. The change in control agreements provide for certain payments and other benefits to be payable upon a change in control and a subsequent termination of employment, either involuntary or for a good reason. In order to receive any payments under the agreements, the Named Executive Officer must sign a waiver that includes a one-year non-competition clause and two-year non-solicitation and non-disparagement clauses.

A change in control is defined in the agreements as:

- an acquisition of 30 percent or more of our common stock, except for certain defined acquisitions, such as acquisition by employee benefit plans, us, any of our subsidiaries, or acquisition by an underwriter holding the securities in connection with a public offering thereof; or

- members of our incumbent Board of Directors cease to constitute at least two-thirds of the members of the Board of Directors, with the incumbent Board of Directors being defined as those individuals consisting of the Board of Directors on the date the agreement was executed and any other directors elected subsequently whose election was approved by the incumbent Board of Directors; or
- approval by our shareholders of:
  - a merger, consolidation, or reorganization;
  - liquidation or dissolution; or
  - an agreement for sale or other disposition of all or substantially all of our assets, with exceptions for transactions which do not involve an effective change in control of voting securities or Board of Directors membership, and transfers to subsidiaries or sale of subsidiaries; and
- all regulatory approvals required to effect a change in control have been obtained and the transaction constituting the change in control has been consummated.

In the change in control agreements, a good reason for termination that triggers payment of benefits includes:

- a material reduction of the executive's authority, duties or responsibilities;
- a reduction in the executive's annual compensation or any failure to pay the executive any compensation or benefits to which he or she is entitled within seven days of the date due;
- any material breach by us of any provisions of the change in control agreement;
- requiring the executive to be based outside a 50-mile radius from his or her usual and normal place of work; or
- our failure to obtain an agreement, satisfactory to the executive, from any successor company to assume and agree to perform under the change in control agreement.

Upon a change in control, Mr. Emery will have an employment contract for a three-year period and the other Named Executive Officers (NEOs) will have an employment contract for a two-year period, but not beyond age 65 ("employment term"). During this employment term, the executive will receive annual compensation at least equal to the highest rate in effect at any time during the one-year period preceding the change in control and will also receive employment welfare benefits, pension benefits and supplemental retirement benefits on a basis no less favorable than those received prior to the change in control. Annual compensation is defined to include amounts which are includable in the gross income of the executive for federal income tax purposes, including base salary, targeted short-term incentive, targeted long-term incentive grants and awards, and matching contributions or other benefits payable under the 401(k) Retirement Savings Plan, but exclude restricted stock awards, performance units or stock options that become vested or exercisable pursuant to a change in control.

If a Named Executive Officer's employment is terminated prior to the end of the employment term by us for cause or disability, by reason of the Named Executive Officer's death, or by the Named Executive Officer without good reason, the Named Executive Officer will receive all amounts of compensation earned or accrued through the termination date. If the Named Executive Officer's employment is terminated because of death or disability, the Named Executive Officer or his beneficiaries will also receive a pro rata bonus equal to 100 percent of the target incentive for the portion of the year served.

If Mr. Emery's employment is terminated during the employment term (other than by reason of death) (i) by us other than for cause or disability, or (ii) by Mr. Emery for a good reason, then Mr. Emery is entitled to the following benefits:

- all accrued compensation and a pro-rata bonus (the same as Mr. Emery or Mr. Emery's beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to 2.99 times Mr. Emery's severance compensation defined as his base salary and short-term incentive target on the date of the change in control; provided that if Mr. Emery has attained the age of 62 on the termination date, the severance payment will be adjusted for the ratio of the number of days remaining to his 65th birthday to 1,095 days;
- continuation of employee welfare benefits for three years following the termination date unless Mr. Emery becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of Mr. Emery or his eligible dependents;
- following the three-year period, Mr. Emery may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at his election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- three additional years of service and age will be credited to Mr. Emery's retiree medical savings account and the account balance will become fully vested and he is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the three year continuation period;

- three years of additional credited service under the 2005 Pension Equalization Plan, Pension Restoration Plan and Pension Plan; and
- outplacement assistance services for up to six months.

In connection with Mr. Emery's retirement as President and Chief Executive Officer, the Compensation Committee does not intend to renew Mr. Emery's Change in Control agreement beyond its current expiration on November 15, 2019.

If any other NEO's employment is terminated during the employment term (other than by death) (i) by us other than for cause or disability, or (ii) by the NEO for a good reason, then the NEO is entitled to the following benefits:

- all accrued compensation and a pro-rata bonus (the same as the NEO or the NEO's beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to two times the NEO's severance compensation defined as the NEO's base salary and short-term incentive target on the date of the change in control; provided that if the NEO has attained the age of 63 on the termination date, the severance payment shall be adjusted for the ratio of the number of days remaining to the NEO's 65th birthday to 730 days;
- continuation of employee welfare benefits for two years following the termination date unless the NEO becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of the NEO or the NEO's eligible dependents;
- following the two-year period, the NEO may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at the NEO’s election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- two additional years of service and age will be credited to the NEO's retiree medical savings account and the account balance will become fully vested and the NEO is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the two year continuation period;
- two years of additional credited service under the executives’ applicable retirement plans; and
- outplacement assistance services for up to six months.

The change in control agreements do not contain a benefit to cover any excise tax imposed by Section 4999 of the Internal Revenue Code of 1986. The executive must sign a waiver and release agreement in order to receive the severance payment.

PAY RATIO FOR 2018

We are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Mr. David Emery, our Chief Executive Officer in 2018.

Based on the information below for the fiscal year 2018 and calculated in a manner consistent with Item 402(u) of Regulation S-K, we reasonably estimate that the ratio of our CEO's annual total compensation to the annual total compensation of our median employee was 49:1.

Name	Year	Salary	Stock Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value[2]	All Other Compensation[3]	Total
David R. Emery	2018	$820,000	$1,943,679	$1,196,503	$523,260	$140,256	$4,623,698
Median Employee [1]	2018	$80,337	$—	$8,116	$—	$5,023	$93,476

[1] We identified our median employee based on the year-to-date total cash compensation actually paid as of October 3, 2017 to all of our employees, other than our CEO, who were employed on October 3, 2017. There has been no change in employee population or employee compensation that we reasonably believe would result in a significant change in our pay ratio disclosure. Accordingly, the Company utilized the same employee as the median employee for 2018.

[2] See Note 4 to our Summary Compensation Table for a description of how the values in the Change in Pension Value column are calculated.

[3]All Other Compensation includes 401(k) match, dividends on restricted stock and other personal benefits for Mr. Emery and only the 401(k) match for the median employee.

PROPOSAL 3	ADVISORY VOTE ON OUR EXECUTIVE COMPENSATION

We are providing shareholders with an annual advisory, non-binding vote on the executive compensation of our Named Executive Officers (commonly referred to as “say on pay”). Accordingly, shareholders will vote on approval of the following resolution:

> RESOLVED, that the shareholders approve, on an advisory basis, the compensation of our Named Executive Officers as disclosed in the Compensation Discussion and Analysis section, the accompanying compensation tables and the related narrative disclosure in this proxy statement.

This vote is non-binding. The Board of Directors and the Compensation Committee expect to consider the outcome of the vote when considering future executive compensation decisions to the extent they can determine the cause or causes of any significant negative voting results. At our 2018 annual meeting, shareholders owning 96 percent of the shares voted approved our executive compensation.

As described at length in the Compensation Discussion and Analysis section of this proxy statement, we believe our executive compensation program is reasonable, competitive and strongly focused on pay for performance. The compensation of our Named Executive Officers varies depending upon the achievement of pre-established performance goals, both individual and corporate. Our short-term incentive is tied to earnings per share targets that reward our executives when they deliver targeted financial results. Our long-term incentives are tied to market performance with 50 percent delivered in restricted stock and 50 percent delivered in performance shares. Entitlement to the performance shares is based on our total shareholder return over a three-year performance period compared to our Performance Peer Group. Through stock ownership guidelines, equity incentives and clawback provisions, we align the interests of our executives with those of our shareholders and our long-term interests. Our executive compensation policies have enabled us to attract and retain talented and experienced senior executives who can drive financial and strategic growth objectives that are intended to enhance shareholder value. We believe that the 2018 compensation of our Named Executive Officers was appropriate and aligned with our 2018 results and positions us for long-term growth.

Shareholders are encouraged to read the Compensation Discussion and Analysis, the accompanying compensation tables, and the related narrative disclosures to better understand the compensation of our Named Executive Officers.

The advisory resolution to approve executive compensation is non-binding. However, our Board of Directors will consider shareholders to have approved our executive compensation if the number of votes cast “For” the proposal exceeds the number of votes cast “Against” the proposal. Abstentions and broker non-votes will have no effect on such vote.

The Board of Directors recommends a vote *FOR* the advisory vote on executive compensation.

TRANSACTION OF OTHER BUSINESS

Our Board of Directors does not intend to present any business for action by our shareholders at the meeting except the matters referred to in this proxy statement. If any other matters should be properly presented at the meeting, it is the intention of the persons named in the accompanying form of proxy to vote thereon in accordance with the recommendations of our Board of Directors.

SHAREHOLDER PROPOSALS FOR 2020 ANNUAL MEETING

Shareholder proposals intended to be presented at our 2020 annual meeting of shareholders and considered for inclusion in our proxy materials must be received by our Corporate Secretary in writing at our executive offices at 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to November 16, 2019. Any proposal submitted must be in compliance with Rule 14a-8 of Regulation 14A of the Securities and Exchange Commission.

Additionally, a shareholder may submit a proposal or director nominee for consideration at our 2020 annual meeting of shareholders, but not for inclusion of the proposal or director nominee in our proxy materials, if the shareholder gives timely written notice of such proposal in accordance with Article I, Section 9 of our Bylaws. In general, Article I, Section 9 provides that, to be timely, a shareholder’s notice must be delivered to our Corporate Secretary in writing not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders.

Our 2019 annual meeting is scheduled for April 30, 2019. Ninety days prior to the first anniversary of this date will be January 31, 2020, and 120 days prior to the first anniversary of this date will be January 1, 2020. For business to be properly requested by the shareholder to be brought before the 2020 annual meeting of shareholders, the shareholder must comply with all of the requirements of Article I, Section 9 of our Bylaws, not just the timeliness requirements set forth above.

SHARED ADDRESS SHAREHOLDERS

In accordance with a notice sent to eligible shareholders who share a single address, we are sending only one annual report and proxy statement to that address unless we receive instructions to the contrary from any shareholder at that address. This practice, known as “householding,” is designed to reduce our printing and postage costs. However, if a shareholder of record residing at such an address wishes to receive a separate annual report or proxy statement in the future, he or she may contact Shareholder Relations at the below address.

Shareholder Relations
Black Hills Corporation
7001 Mount Rushmore Road
P.O. Box 1400
Rapid City, SD 57709
(605) 721-1700

Eligible shareholders of record receiving multiple copies of our annual report and proxy statement can request householding by contacting us in the same manner. Shareholders who own shares through a bank, broker or other nominee can request householding by contacting the nominee.

We hereby undertake to deliver promptly, upon written or oral request, a separate copy of the annual report to shareholders, or proxy statement, as applicable, to our shareholders at a shared address to which a single copy of the document was delivered.

Please vote your shares by telephone, by the Internet or by promptly returning the accompanying form of proxy, whether or not you expect to be present at the annual meeting.

ANNUAL REPORT ON FORM 10-K

A copy of our Annual Report on Form 10-K (excluding exhibits) for the year ended December 31, 2018, which is required to be filed with the Securities and Exchange Commission, will be made available to shareholders to whom this proxy statement is mailed, without charge, upon written or oral request to Shareholder Relations, Black Hills Corporation, 7001 Mount Rushmore Road, P.O. Box 1400, Rapid City, SD 57709, Telephone Number: (605) 721-1700. Our Annual Report on Form 10-K also may be accessed through our website at www.blackhillscorp.com.

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD ON APRIL 30, 2019

Shareholders may view this proxy statement, our form of proxy and our 2018 Annual Report to Shareholders over the Internet by accessing our website at www.blackhillscorp.com. Information on our website does not constitute a part of this proxy statement.

By Order of the Board of Directors,

BRIAN G. IVERSON
Senior Vice President, General Counsel and Corporate Secretary

Dated: March 15, 2019

APPENDIX A	RECONCILIATION OF NON-GAAP FINANCIAL MEASURES

	Year Ended	
	Dec. 31, 2018	Dec. 31, 2017
EPS from continuing operations (GAAP)	$ 4.78	$ 3.52
Adjustments:		
Legal restructuring income tax benefits	(1.31)	—
Tax reform and other tax items	(0.07)	(0.21)
External acquisition costs	—	0.08
Total adjustments	(1.24)	(0.13)
Tax on adjustments:		
Acquisition costs	—	(0.03)
Total adjustments, net of tax	(1.24)	(0.16)
EPS from continuing operations, as adjusted (Non-GAAP)	$ 3.54	$ 3.36

- 5.4 percent growth in earnings per share from continuing operations, as adjusted, from 2017 to 2018.

USE OF NON-GAAP FINANCIAL MEASURE

In addition to presenting our earnings information in conformity with Generally Accepted Accounting Principles (GAAP), the Company has provided non-GAAP earnings data reflecting adjustments for special items as specified in the Reconciliation of Non-GAAP Financial Measures table above. EPS from continuing operations, as adjusted, is defined as EPS from continuing operations adjusted for expenses and other items that the Company believes do not reflect the Company's core operating performance. The Company believes that non-GAAP financial measures are useful to investors because the items excluded are not indicative of the Company's continuing operating results. The Company's management uses these non-GAAP financial measures as an indicator for planning and forecasting future periods. These non-GAAP measures have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our presentation of these non-GAAP financial measures should not be construed as an inference that our future results will be unaffected by other income and expenses that are unusual, non-routine or non-recurring.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

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

For the fiscal year ended December 31, 2018

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________ to __________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	7001 Mount Rushmore Road	IRS Identification Number
	Rapid City, South Dakota 57702	46-0458824

Registrant's telephone number, including area code
(605) 721-1700

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

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

FORM 10K

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

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

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

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

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2018	$3,239,030,444

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

Class	Outstanding at January 31, 2019
Common stock, $1.00 par value	60,003,965 shares

Documents Incorporated by Reference

Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2019 Annual Meeting of Stockholders to be held on April 30, 2019, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

AFUDC	Allowance for Funds Used During Construction
AltaGas	AltaGas Renewable Energy Colorado LLC, a subsidiary of AltaGas Ltd.
AOCI	Accumulated Other Comprehensive Income
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila, Inc.
APSC	Arkansas Public Service Commission
Arkansas Gas	Includes the acquired SourceGas utility Black Hills Energy Arkansas, Inc. utility operations (doing business as Black Hills Energy)
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcf	Billion cubic feet
BHC	Black Hills Corporation; the Company
BHEP	Black Hills Exploration and Production, Inc., our previous Oil and Gas segment. As of December 31, 2018, we have completed the exit of the Oil and Gas business.
BHSC	Black Hills Service Company LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Gas	Black Hills Gas, LLC, a subsidiary of Black Hills Gas Holdings, which was previously named SourceGas LLC.
Black Hills Gas Holdings	Black Hills Gas Holdings, LLC, a subsidiary of Black Hills Utility Holdings, which was previously named SourceGas Holdings LLC
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Colorado Electric	Includes Colorado Electric's utility operations
Black Hills Energy Colorado Gas	Includes Black Hills Energy Colorado Gas utility operations, as well as RMNG
Black Hills Energy Iowa Gas	Includes Black Hills Energy Iowa gas utility operations
Black Hills Energy Kansas Gas	Includes Black Hills Energy Kansas gas utility operations
Black Hills Energy Nebraska Gas	Includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Nebraska gas operations
Black Hills Energy Services	A Choice Gas supplier acquired in the SourceGas Acquisition
Black Hills Energy South Dakota Electric	Includes Black Hills Power's operations in South Dakota, Wyoming and Montana
Black Hills Energy Wyoming Electric	Includes Cheyenne Light's electric utility operations
Black Hills Energy Wyoming Gas	Includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming gas operations
Black Hills Gas Distribution	Black Hills Gas Distribution, LLC, a company acquired in the SourceGas Acquisition that conducts the gas distribution operations in Nebraska and Wyoming. It was formerly named SourceGas Distribution LLC.
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation

BLM	United States Bureau of Land Management
Btu	British thermal unit
Busch Ranch I	Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and Black Hills Electric Generation. Colorado Electric and Black Hills Electric Generation each have a 50% ownership interest in the wind farm.
Busch Ranch II	Busch Ranch II wind project is under construction as a 60 MW wind farm near Pueblo, Colorado, built by Black Hills Electric Generation to provide wind energy to Colorado Electric through a 25-year power purchase agreement.
Ceiling Test	Related to our Oil and Gas subsidiary, capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties.
CAPP	Customer Appliance Protection Plan - acquired in the SourceGas Acquisition
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural-gas fired generating facility jointly owned by Black Hills Power and Cheyenne Light in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
Choice Gas Program	The unbundling of the natural gas service from the distribution component, which opens up the gas supply for competition allowing customers to choose from different natural gas suppliers. Black Hills Gas Distribution distributes the gas and Black Hills Energy Services is one of the Choice Gas suppliers.
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Gas	Black Hills Colorado Gas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Interstate Gas (CIG)	Colorado Interstate Natural Gas Pricing Index
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by Capital at such time. Capital being Consolidated Net-Worth (excluding noncontrolling interest) plus Consolidated Indebtedness (including letters of credit and certain guarantees issued) as defined within the current Credit Agreement.
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.
CVA	Credit Valuation Adjustment
DART	Days Away Restricted Transferred (number of cases with days away from work or job transfer or restrictions multiplied by 200,000 then divided by total hours worked for all employees during the year covered)
DC	Direct current
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
DRSPP	Dividend Reinvestment and Stock Purchase Plan
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)

EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Electricity purchased by one utility from another utility to take the place of electricity that would have cost more to produce on the utility's own system
EIA	Environmental Improvement Adjustment
EPA	United States Environmental Protection Agency
Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs due 2028.
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Global Settlement	Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants
IRS	United States Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Loveland Area Project	Part of the Western Area Power Association transmission system
MAPP	Mid-Continent Area Power Pool
MATS	Utility Mercury and Air Toxics Rules under the United States EPA National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units
Mbbl	Thousand barrels of oil
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a regulated utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MGP	Manufactured Gas Plant
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent

Moody's	Moody's Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
NERC	North American Electric Reliability Corporation
NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
NOAA	National Oceanic and Atmospheric Administration
NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA's National Weather Service.
NO_x	Nitrogen oxide
NOL	Net operating loss
NPSC	Nebraska Public Service Commission
NWPL	Northwest Interstate Natural Gas Pricing Index
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	Occupational Safety & Health Administration
OSM	U.S. Department of the Interior's Office of Surface Mining
PCA	Power Cost Adjustment
PCCA	Power Capacity Cost Adjustment
Peak View	60 MW wind generating project owned by Colorado Electric, placed in service on November 7, 2016 and adjacent to Busch Ranch I Wind Farm
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado
PUHCA 2005	Public Utility Holding Company Act of 2005
REPA	Renewable Energy Purchase Agreement
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2023
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas Distribution in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SAIDI	System Average Interruption Duration Index
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
Service Guard	Home appliance repair product offering for both natural gas and electric
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
SPP	Southwest Power Pool, Inc. which oversees the bulk electric grid and wholesale power market in the central United States
SourceGas	SourceGas Holdings, LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	The acquisition of SourceGas Holdings LLC by Black Hills Utility Holdings

SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming and Montana
SSIR	System Safety and Integrity Rider
System Peak Demand	Represents the highest point of customer usage for a single hour for the system in total. Our system peaks include demand loads for 100% of plants regardless of joint ownership.
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
TCIR	Total Case Incident Rate (average number of work-related injuries incurred by 100 workers during a one-year period)
Tech Services	Non-regulated product lines within Black Hills Corporation that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owner gas infrastructure facilities, typically through one-time contracts.
TFA	Transmission Facility Adjustment
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
Winter Storm Atlas	An October 2013 blizzard that impacted South Dakota Electric. It was the second most severe blizzard in Rapid City's history.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, owned 80% by PacifiCorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.
Wyoming Electric	Includes Cheyenne Light's electric utility operations
Wyoming Gas	Includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming gas operations

Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

Forward-Looking Information

This Form 10-K contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management's Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the "Company," "we," "us" or "our"), is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, with the purchase of the Wyodak coal mine, we began producing and selling energy through non-regulated businesses.

We operate our business in the United States, reporting our operating results through our regulated Electric Utilities, regulated Gas Utilities, Power Generation and Mining segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 212,000 electric customers in Colorado, Montana, South Dakota and Wyoming. Our Electric Utilities own 939 MW of generation and 8,858 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,054,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate approximately 4,700 miles of intrastate gas transmission pipelines and 41,158 miles of gas distribution mains and service lines, seven natural gas storage sites, over 45,000 horsepower of compression and nearly 600 miles of gathering lines.

Our Power Generation segment produces electric power from its wind, natural gas and coal generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Mining segment produces coal at our mine near Gillette, Wyoming, and sells the coal primarily under long-term contracts to mine-mouth electric generation facilities owned by our Electric Utilities and Power Generation businesses.

Electric Utilities Segment

We conduct electric utility operations through our South Dakota, Wyoming and Colorado subsidiaries. Our Electric Utilities generate, transmit and distribute electricity to approximately 212,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services through our Tech Services product lines.

Capacity and Demand. System peak demands for the Electric Utilities for each of the last three years are listed below:

	System Peak Demand (in MW)					
	2018		2017		2016	
	Summer	Winter	Summer	Winter	Summer	Winter
South Dakota Electric	437	379	447	402	438	389
Wyoming Electric [(a)]	254	238	249	230	236	230
Colorado Electric [(b)]	413	313	398	299	412	302
Total Electric Utilities' Peak Demands	1,104	930	1,094	931	1,086	921

(a) The July 2018 summer peak load of 254 surpassed previous summer peak record load of 249 set in July 2017. The December 2018 winter peak load of 238 surpassed the previous winter peak record load of 230 set in December 2016.
(b) The July 2018 summer peak load of 413 surpassed previous summer peak record load of 412 set in July 2016. The October 2018 winter peak load of 313 surpassed previous winter peak load of 310 set in February 2011.

FORM 10K

Regulated Power Plants. As of December 31, 2018, our Electric Utilities' ownership interests in electric generating plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned Capacity (MW)	Year Installed
South Dakota Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	58%	55.0	2014
Wygen III [(b)]	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak [(c)]	Coal	Gillette, Wyoming	20%	72.4	1978
Neil Simpson CT	Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, South Dakota	100%	80.0	1977-1979
Wyoming Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT [(a)]	Gas	Cheyenne, Wyoming	100%	37.0	2014
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Colorado Electric [(e)]:					
Busch Ranch I Wind Farm [(d)]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View Wind Farm	Wind	Pueblo, Colorado	100%	60.0	2016
Pueblo Airport Generation	Gas	Pueblo, Colorado	100%	180.0	2011
Pueblo Airport Generation CT	Gas	Pueblo, Colorado	100%	40.0	2016
AIP Diesel	Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1 and #3-5	Oil	Pueblo, Colorado	100%	8.0	1964
Diesel #1-5	Oil	Rocky Ford, Colorado	100%	10.0	1964
Total MW Capacity				939.1	

(a) Cheyenne Prairie, a 132 MW natural gas-fired power generation facility supports the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 37 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 95 MW unit that is jointly-owned by Wyoming Electric (40 MW) and South Dakota Electric (55 MW).

(b) Wygen III, a 110 MW mine-mouth coal-fired power plant, is operated by South Dakota Electric. South Dakota Electric has a 52% ownership interest, MDU owns 25% and the City of Gillette owns the remaining 23% interest. Our WRDC coal mine supplies all of the fuel for the plant.

(c) Wyodak, a 362 MW mine-mouth coal-fired power plant, is owned 80% by PacifiCorp and 20% by South Dakota Electric. This baseload plant is operated by PacifiCorp and our WRDC coal mine supplies all of the fuel for the plant.

(d) Busch Ranch I Wind Farm, a 29 MW wind farm, is operated by Colorado Electric. Colorado Electric has a 50% ownership interest in the wind farm and Black Hills Electric Generation owns the remaining 50%. Black Hills Electric Generation purchased the remaining 50% from AltaGas on December 11, 2018. Colorado Electric has a PPA with Black Hills Electric Generation for its 14.5 MW of power from the wind farm. The terms of the PPA are the same as the previous PPA with AltaGas.

(e) On April 25, 2018, Colorado Electric received approval from the CPUC to contract with Black Hills Electric Generation for the 60 MW Busch Ranch II wind project. The project is currently under construction and is expected to be in service by the end of 2019.

The Electric Utilities' annual average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 was as follows:

Fuel Source (dollars per MWh)	2018	2017	2016
Coal	$ 11.10	$ 10.95	$ 11.27
Natural Gas	$ 33.42	$ 34.05	$ 30.59
Diesel Oil [(a)]	$ 329.27	$ 210.11	$ 149.13
Total Average Fuel Cost	$ 13.53	$ 12.80	$ 12.99
Purchased Power - Coal, Gas and Oil	$ 45.62	$ 45.63	$ 48.36
Purchased Power - Renewable Sources	$ 54.31	$ 53.08	$ 51.95

(a) Included in the Price per MWh for Diesel Oil are unit start-up costs. The diesel-fueled generating units are generally used as supplemental peaking units and the cost per MWh is reflective of how often the units are started and how long the units are run.

Our Electric Utilities' power supply, by resource as a percent of the total power supply for our energy needs for the years ended December 31 was as follows:

Power Supply	2018	2017	2016
Coal	32%	32%	33%
Gas, Oil and Wind	10	8	7
Total Generated	42	40	40
Purchased [(a)]	58	60	60
Total	100%	100%	100%

(a) Wind represents approximately 6%, 6% and 7% of our purchased power in 2018, 2017, and 2016, respectively.

Purchased Power. We have executed various agreements to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation. Key contracts include:

- South Dakota Electric's PPA with PacifiCorp expiring on December 31, 2023, which provides for the purchase of 50 MW of coal-fired baseload power;

- Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, which provides 200 MW of energy and capacity to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is reported and accounted for as a capital lease within our business segments and is eliminated on the accompanying Consolidated Financial Statements;

- Colorado Electric's PPA with Black Hills Electric Generation, which provides up to 14.5 MW of wind energy from Black Hills Electric Generation's owned interest in the Busch Ranch I Wind Farm. This PPA is the same as the previous agreement with AltaGas, which expires on October 16, 2037;

- Wyoming Electric's PPA with Black Hills Wyoming expiring on December 31, 2022, whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. On November 30, 2018, Wyoming Electric submitted its 2018 integrated resource plan to the WPSC, which included the recommendation that Wyoming Electric acquire Wygen I. Review of Wyoming Electric's integrated resource plan is subject to an open public process governed by the WPSC. The purchase of Wygen I would require approval of a CPCN by the WPSC and approval by FERC. The review process is expected to be completed by year-end 2019.

The purchase price related to the option is $2.1 million per MW (65 MWs), adjusted for all depreciated capital additions since 2009, and reduced by depreciation (approximately $5 million per year) over a 35-year life beginning January 1, 2009. The net book value of Wygen I at December 31, 2018 was $75 million and if Wyoming Electric had exercised the purchase option at year-end 2018, the estimated purchase price would have been approximately $139 million;

- Wyoming Electric's 20-year PPA with Duke Energy expiring on September 3, 2028, which provides up to 29.4 MW of wind energy from the Happy Jack Wind Farm to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 50% of the facility's output to South Dakota Electric;

- Wyoming Electric's 20-year PPA with Duke Energy expiring on September 30, 2029, which provides up to 30 MW of wind energy from the Silver Sage wind farm to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of the facility's output to South Dakota Electric;

- Wyoming Electric and South Dakota Electric's Generation Dispatch Agreement requires South Dakota Electric to purchase all of Wyoming Electric's excess energy; and

- South Dakota Electric's PPA with Platte River Power Authority to purchase up to 12 MW of wind energy through Platte River Power Authority's agreement with Silver Sage. This agreement will expire September 30, 2029.

Power Sales Agreements. Our Electric Utilities have various long-term power sales agreements. Key agreements include:

- MDU owns a 25% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, South Dakota Electric will provide MDU with 25 MW from its other generation facilities or from system purchases with reimbursement of costs by MDU;

- South Dakota Electric has an agreement through December 31, 2023 to provide MDU capacity and energy up to a maximum of 50 MW;

- The City of Gillette owns a 23% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, South Dakota Electric will provide the City of Gillette with its first 23 MW from its other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, South Dakota Electric will also provide the City of Gillette its operating component of spinning reserves;

- South Dakota Electric has an agreement through December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals; and

- South Dakota Electric has an amended agreement, effective January 1, 2019, to supply up to 20 MW of energy and capacity to MEAN under a contract that expires in 2028. The terms of the contract run from June 1 through May 31 for each interval listed below. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

2019-2020	15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2022	15 MW - 7 MW contingent on Wygen III and 8 MW contingent on Neil Simpson II
2022-2023	15 MW - 8 MW contingent on Wygen III and 7 MW contingent on Neil Simpson II
2023-2028	10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

Transmission and Distribution. Through our Electric Utilities, we own electric transmission systems composed of high voltage transmission lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly own high voltage lines with Basin Electric and Powder River Energy Corporation.

At December 31, 2018, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
South Dakota Electric	South Dakota, Wyoming	1,231	2,539
South Dakota Electric - Jointly Owned [(a)]	South Dakota, Wyoming	44	—
Wyoming Electric	Wyoming	49	1,291
Colorado Electric	Colorado	598	3,106

(a) South Dakota Electric owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65% owned by Basin Electric, provides transmission access to both the WECC region in the West and the SPP region in the East. The transfer capacity of the tie is 200 MW from West to East, and 200 MW from East to West. South Dakota Electric's electric system is located in the WECC region. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids.

South Dakota Electric has firm point-to-point transmission access to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the WECC region through December 31, 2023.

South Dakota Electric also has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming, to serve our power sales contract with MDU through December 31, 2023, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

In order to serve Wyoming Electric's existing load, Wyoming Electric has a network transmission agreement with Western Area Power Association's Loveland Area Project.

Colorado Electric is party to a joint dispatch agreement with PSCo and Platte River Power Authority. This FERC-approved agreement, effective in 2017, is structured to allow PSCo, as administrator, to receive load and generation bid information for all three parties and, on an intra-hour basis, serve the combined utility load utilizing the combined bid generating resources on a least-cost basis. In other words, if one party has excess generation at a lower cost than another party's generation, the administrator will increase dispatch of the lower-cost generation and decrease dispatch of the higher-cost generation. This results in lower energy costs to customers through more efficient dispatch of low-cost generating resources. Under the agreement, Colorado Electric retains the ability to participate or not participate in the joint dispatch at its discretion.

Operating Agreements. Our Electric Utilities have the following material operating agreements:

- Shared Services Agreements -
    - South Dakota Electric, Wyoming Electric, and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.
    - Black Hills Colorado IPP and Colorado Electric are also parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.
    - South Dakota Electric and Wyoming Electric receive certain staffing and management services from BHSC for Cheyenne Prairie.
- Jointly Owned Facilities -
    - South Dakota Electric, the City of Gillette and MDU are parties to a shared joint ownership agreement, whereby South Dakota Electric charges the City of Gillette and MDU for administrative services, plant operations and maintenance for its share of the Wygen III generating facility for the life of the plant.

- ◦ Colorado Electric and Black Hills Electric Generation are parties to a shared joint ownership agreement whereby Colorado Electric charges Black Hills Electric Generation for operations and maintenance for its share of the Busch Ranch I Wind Farm.

Seasonal Variations of Business. Our Electric Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, demand is often greater in the summer and winter months for cooling and heating, respectively. Because our Electric Utilities have a diverse customer and revenue base, and we have historically optimized the utilization of our electric power supply resources, the impact on our operations may not be as significant when weather conditions are warmer in the winter and cooler in the summer.

Competition. We generally have limited competition for the retail generation and distribution of electricity in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have not had a material impact on our utilities. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated independent power producers for the right to provide electric energy and capacity for Colorado Electric when resource plans require additional resources.

Rates and Regulation. Our Electric Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their states to secure bonds or other securities. The following table provides regulatory information for each of our Electric Utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms	Percentage of Power Marketing Profit Shared with Customers
South Dakota Electric	WY	9.9%	8.13%	46.7%/53.3%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TCA, Energy Efficiency Cost Recovery/DSM	70%
	SD		7.76%			5/2014	Transmission Facility Adjustment (TFA) Tariff	N/A
	SD		7.76%			6/2011	Environmental Improvement Adjustment (EIA) Tariff	N/A
	FERC	10.8%	8.76%	43%/57%		2/2009	FERC Transmission Tariff	N/A
Wyoming Electric	WY	9.9%	7.98%	46%/54%	$376.8	10/2014	PCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
	FERC	10.6%	8.51%	46%/54%	$31.5	5/2014	FERC Transmission Tariff	N/A
Colorado Electric	CO	9.37%	7.43%	47.6%/52.4%	$539.6	1/2017	ECA, TCA, PCCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment	90%
	CO	9.37%	6.02%	67.3%/32.7%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	N/A

The regulatory provisions for recovering the costs to supply electricity vary by state. In all states, subject to thresholds noted below, we have cost adjustment mechanisms for our Electric Utilities that allow us to pass the prudently-incurred cost of fuel and purchased power through to customers. These mechanisms allow the utility operating in that state to collect, or refund the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. Some states in which our utilities operate also allow the utility operating in that state to automatically adjust rates periodically for the cost of new transmission or environmental improvements and, in some instances, the utility has the opportunity to earn its authorized return on new capital investment immediately.

The significant mechanisms we have in place include the following by utility and state:

South Dakota Electric has:

- An approved annual Environmental Improvement Adjustment (EIA) tariff which recovers costs associated with generation plant environmental improvements. South Dakota Electric also has a Transmission Facility Adjustment (TFA) tariff which recovers the costs associated with transmission facility improvements. The EIA and TFA were suspended for a six-year moratorium period effective July 1, 2017. See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

- An annual adjustment clause which provides for the over or under recovery of fuel and purchased power cost incurred to serve South Dakota customers. Additionally, this ECA contains an off-system sales sharing mechanism in which South Dakota customers will receive a credit equal to 100% of off-system power marketing operating income from the first $1.0 million of power marketing margin from short-term sales and a credit equal to 70% of power marketing margins from short-term sales in excess of the first $1.0 million. South Dakota Electric retains the remaining 30%. During the six-year moratorium period effective July 1, 2017, the 100% credit of power marketing margin increased from $1.0 million to $2.0 million. The ECA methodology allows us to directly assign renewable resources and firm purchases to the customer load. In Wyoming, a similar fuel and purchased power cost adjustment is also in place.

- An approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric's open access transmission tariff.

In Wyoming, Wyoming Electric has:

- An annual cost adjustment mechanism that allows us to pass the prudently-incurred costs of fuel and purchased power through to electric customers. The annual cost adjustment allows for recovery of 85% of coal and coal-related cost per kWh variances from base, and recovery of 95% of purchased power, transmission, and natural gas cost per kWh variances from base.

- An approved FERC Transmission Tariff that determines the revenue component of Wyoming Electric's open access transmission tariff.

In Colorado, Colorado Electric has:

- A quarterly ECA rider that allows us to recover forecasted increases or decreases in purchased energy and fuel costs, including the recovery for amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others, and the sharing of off-system sales margins, less certain operating costs (customer receives 90%). The ECA provides for not only direct recovery, but also for the issuance of credits for decreases in purchased energy, fuel costs and eligible energy resources.

- An annual TCA rider that includes nine months of actual transmission investment and three months of forecasted investment, with an annual true-up mechanism.

- A Clean Air Clean Jobs Act Adjustment rider rate that collects the authorized revenue requirement for the 40 MW combustion turbine placed in service on December 31, 2016 with rates effective January 1, 2017.

- A Renewable Energy Standard Adjustment rider that is specifically designed for meeting the requirements of Colorado's renewable energy standard and most recently includes cost recovery for Peak View.

Tariff Filings

On December 17, 2018, South Dakota Electric and Wyoming Electric filed for approval of new, voluntary renewable energy tariffs to serve customer requests for renewable energy resources. Requests to approve the voluntary tariffs, known as Renewable Ready Service Tariffs, were submitted to the SDPUC and WPSC. The renewable ready tariffs would provide large commercial and industrial customers and governmental agencies an option to purchase utility-scale renewable energy. As proposed, customers would be able to enter into contracts with Black Hills Energy to purchase renewable energy for periods of five to 25 years.

On September 28, 2018, Wyoming Electric filed for approval of a new innovative tariff to serve blockchain business customers in Wyoming. Request to approve the blockchain tariff, known as Blockchain Interruptible Service ("BCIS") tariff, was submitted to the WPSC. The BCIS tariff, as proposed, was designed in response to blockchain business recruiting initiatives of the state of Wyoming and would provide the opportunity for Wyoming Electric to attract blockchain business and continue to provide safe and reliable service without negatively impacting existing customers.

See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information regarding current electric rate activity.

Operating Statistics. The following tables summarize information for our Electric Utilities:

Degree Days	2018		2017		2016	
	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)
Heating Degree Days:						
South Dakota Electric	7,749	8%	6,870	(4)%	6,402	(10)%
Wyoming Electric	7,036	(7)%	6,623	(12)%	6,363	(14)%
Colorado Electric	5,119	4%	4,693	(16)%	4,658	(16)%
Combined (a)	6,405	3%	5,826	(11)%	5,595	(13)%
Cooling Degree Days:						
South Dakota Electric	488	(23)%	709	11%	646	(4)%
Wyoming Electric	430	24%	429	23%	460	31%
Colorado Electric	1,420	58%	1,027	14%	1,358	42%
Combined (a)	902	29%	798	14%	935	26%

(a) The combined degree days are calculated based on a weighted average of total customers by state.
(b) 30-Year Average is from NOAA Climate Normals.

	Electric Revenue (in thousands)			Quantities Sold (MWh)		
	2018	2017	2016	2018	2017	2016
Residential	$ 218,558	$ 210,172	$ 208,725	1,450,585	1,390,952	1,395,097
Commercial	250,894	258,754	258,768	2,034,917	2,038,495	2,067,486
Industrial	124,668	122,958	118,181	1,682,074	1,598,755	1,515,553
Municipal	17,871	18,144	17,821	160,913	160,882	162,383
Subtotal Retail Revenue - Electric	611,991	610,028	603,495	5,328,489	5,189,084	5,140,519
Contract Wholesale	33,688	30,435	17,037	900,854	722,659	246,630
Off-system/Power Marketing Wholesale	24,800	21,111	22,355	673,994	661,263	769,843
Other [(a)]	40,972	43,076	34,394	—	—	—
Total Revenue and Energy Sold	711,451	704,650	677,281	6,903,337	6,573,006	6,156,992
Other Uses, Losses or Generation, net	—	—	—	470,250	468,179	433,400
Total Revenue and Energy	711,451	704,650	677,281	7,373,587	7,041,185	6,590,392
Less cost of fuel and purchased power	277,093	268,405	261,349			
Gross Margin [(b)]	$ 434,358	$ 436,245	$ 415,932			

(a) Other revenue in 2018 reflects the impact of revenue reserved in accordance with the TCJA.
(b) Non-GAAP measure.

	Electric Revenue (in thousands)			Gross Margin [(a)] (in thousands)			Quantities Sold (MWh) [(b)]		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
South Dakota Electric	$ 298,080	$ 288,433	$ 267,632	$ 205,194	$ 200,795	$ 192,606	3,360,396	3,187,392	2,767,315
Wyoming Electric	162,153	165,127	157,606	83,516	89,371	85,036	1,861,273	1,762,117	1,677,421
Colorado Electric	251,218	251,090	252,043	145,648	146,079	138,290	2,151,918	2,091,676	2,145,656
Total Revenue, Gross Margin, and Quantities Sold	$ 711,451	$ 704,650	$ 677,281	$ 434,358	$ 436,245	$ 415,932	7,373,587	7,041,185	6,590,392

(a) Non-GAAP measure.
(b) Total MWh includes Other Uses, Losses or Generation, net, which is approximately 6%, 6%, and 7% for South Dakota Electric, Wyoming Electric, and Colorado Electric, respectively.

Quantities Generated and Purchased (MWh)	2018	2017	2016
Coal-fired	2,368,506	2,230,617	2,201,757
Natural Gas and Oil	446,373	307,815	343,001
Wind	253,180	239,472	80,582
Total Generated	3,068,059	2,777,904	2,625,340
Purchased	4,305,528	4,263,281	3,965,052
Total Generated and Purchased	7,373,587	7,041,185	6,590,392

Quantities Generated and Purchased (MWh)	2018	2017	2016
Generated:			
South Dakota Electric	1,734,222	1,581,915	1,585,870
Wyoming Electric	852,391	798,024	805,351
Colorado Electric	481,446	397,965	234,119
Total Generated	3,068,059	2,777,904	2,625,340
Purchased:			
South Dakota Electric	1,626,174	1,605,477	1,181,445
Wyoming Electric	1,008,882	964,093	872,070
Colorado Electric	1,670,472	1,693,711	1,911,537
Total Purchased	4,305,528	4,263,281	3,965,052
Total Generated and Purchased	7,373,587	7,041,185	6,590,392

Customers at End of Year	2018	2017	2016
Residential	181,459	179,911	178,333
Commercial	29,299	29,354	29,086
Industrial	84	86	88
Other	1,030	914	1,001
Total Electric Customers at End of Year	211,872	210,265	208,508

Customers at End of Year	2018	2017	2016
South Dakota Electric	72,533	72,184	71,353
Wyoming Electric	42,694	42,130	41,531
Colorado Electric	96,645	95,951	95,624
Total Electric Customers at End of Year	211,872	210,265	208,508

Gas Utilities Segment

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities transport and distribute natural gas through our distribution network to approximately 1,054,000 customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as-available basis.

We also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services has approximately 47,000 retail distribution customers in Nebraska and Wyoming providing unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air, heating and water-heating equipment, and provide associated repair service and appliance protection plans under various trade names. Service Guard and CAPP provide appliance repair services to approximately 62,000 and 28,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

We procure natural gas for our distribution customers from a diverse mix of producers, processors and marketers and generally use hedging, physical fixed-price purchases and market-based price purchases to achieve dollar-cost averaging within our natural gas portfolio. The majority of our procured natural gas is transported in interstate pipelines under firm transportation service agreements with Colorado Interstate Gas Company, Enable Gas Transmission, Tallgrass Interstate Gas Transmission, Natural Gas Pipeline Company of America, Northern Natural Gas, Panhandle Eastern Pipeline Company, Southern Star Central Gas Pipeline, Black Hills Shoshone Pipeline, TransColorado Gas Transmission, WBI Energy Transmission, Rocky Mountain Natural Gas, Ozark Gas Transmission, Liberty Utilities, Texas Eastern Transmission Pipeline, WestGas InterState Pipeline, Public Service Company of Colorado and Red Cedar Gas Gathering.

In addition to company-owned storage assets in Arkansas, Colorado and Wyoming, we also contract with many of the third-party transportation providers noted above for natural gas storage service to provide gas supply during the winter heating season and to meet peak day customer demand for natural gas.

The following table summarizes certain information regarding our regulated underground gas storage facilities as of December 31, 2018:

State	Working Capacity (Mcf)	Cushion Gas (Mcf) [(a)]	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas	8,442,700	12,950,000	21,392,700	196,000
Colorado	2,360,895	6,165,315	8,526,210	30,000
Wyoming	5,733,900	17,145,600	22,879,500	32,950
Total	16,537,495	36,260,915	52,798,410	258,950

(a) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

The following tables summarize certain operating information for our Gas Utilities.

System Infrastructure (in line miles) as of December 31, 2018	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Arkansas	932	4,803	1,122
Colorado	689	6,699	2,457
Nebraska	1,263	8,539	3,203
Iowa	164	2,791	2,667
Kansas	325	2,868	1,347
Wyoming	1,327	3,447	1,215
Total	4,700	29,147	12,011

Degree Days	2018		2017		2016	
	Actual	Variance From 30-Year Average [c]	Actual	Variance From 30-Year Average [c]	Actual	Variance From 30-Year Average [c]
Heating Degree Days:						
Arkansas [a]	4,169	3%	3,295	(19)%	2,397	(41)%
Colorado	6,136	(7)%	5,728	(14)%	5,762	(13)%
Nebraska	6,563	6%	5,554	(10)%	5,457	(12)%
Iowa	7,192	6%	6,149	(9)%	5,997	(11)%
Kansas [a]	5,242	7%	4,452	(9)%	4,307	(12)%
Wyoming	7,425	(1)%	7,123	(5)%	6,750	(10)%
Combined [b]	6,628	2%	5,862	(10)%	5,823	(11)%

(a) Arkansas Gas has a weather normalization mechanism in effect during the months of November through April for customers with residential and certain business rate schedules. Kansas Gas has a weather normalization mechanism within its residential and business rate structure. The weather normalization mechanism in Arkansas differs from that in Kansas in that it only uses one location to calculate the weather, while Kansas uses multiple locations. The weather normalization mechanisms in both Arkansas and Kansas minimize weather impact on gross margins (a non-GAAP measure).

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

(c) 30-Year Average is from NOAA climate normals.

Seasonal Variations of Business. Our Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for natural gas is sensitive to seasonal heating and industrial load requirements, as well as market price. In particular, demand is often greater in the winter months for heating. Natural gas is used primarily for residential and commercial heating, so the demand for this product depends heavily upon weather throughout our service territories, and as a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters. Demand for natural gas can also be impacted by summer weather patterns that are cooler than normal and/or provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation.

Competition. We generally have limited competition for the retail distribution of natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives are aimed at increasing competition. To date, these initiatives have not had a material impact on our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a distribution charge for transporting the gas through our distribution network.

Rates and Regulation. Our Gas Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their states to secure bonds or other securities.

Our Gas Utilities are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure that they recover all the costs prudently incurred in purchasing gas for their customers. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to energy efficiency plans and system safety and integrity investments. The following table provides regulatory information for each of our natural gas utilities:

Subsidiary	Jurisdiction	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms
Gas Utilities:							
Arkansas Gas	AR	9.61%	6.82% [(a)]	50.9%/49.1%	$451.5 [(b)]	10/2018	GCA, Main Replacement Program, At-Risk Meter Relocation Program, Legislative/ Regulatory Mandate and Relocations Rider, Energy Efficiency, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	9.6%	8.41%	50%/50%	$57.5	12/2012	GCA, Energy Efficiency Cost Recovery/DSM
Colorado Gas Dist.	CO	10.0%	8.02%	49.52%/ 50.48%	$127.1	12/2010	GCA, DSM
RMNG	CO	9.9%	6.71%	53.37%/ 46.63%	$118.7	6/2018	System Safety Integrity Rider, Liquids/Off-system/Market Center Services Revenue Sharing
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	$109.2	2/2011	GCA, Energy Efficiency Cost Recovery/DSM/ Capital Infrastructure Automatic Adjustment Mechanism, Gas Supply Optimization revenue sharing
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	$127.9	1/2015	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment
Nebraska Gas	NE	10.1%	9.11%	48%/52%	$161.0	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge
Nebraska Gas Dist.	NE	9.6%	7.67%	48.84%/ 51.16%	$87.6/ $69.8 [(c)]	6/2012	Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice Supplier Fee
Wyoming Gas (Northwest Wyoming)	WY	9.6%	7.75%	46%/54%	$12.9	9/2018	GCA
Wyoming Gas	WY	9.9%	7.98%	46%/54%	$59.6	10/2014	GCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment
Wyoming Gas Dist.	WY	9.92%	7.98%	49.66%/ 50.34%	$100.5	1/2011	Choice Gas Program, Purchased GCA, Usage Per Customer Adjustment

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(a) Arkansas Gas return on rate base adjusted to remove current liabilities from rate case capital structure for comparison with other subsidiaries.

(b) Arkansas Gas rate base is adjusted to include current liabilities for comparison with other subsidiaries.

(c) Total Nebraska Gas Distribution rate base of $87.6 million includes amounts allocated to serve non-jurisdictional and agricultural customers. Jurisdictional Nebraska rate base of $69.8 million excludes those amounts allocated to serve non-jurisdictional and agricultural customers and is used for calculation of jurisdictional base rates.

All of our Gas Utilities, except where Choice Gas is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews. Some of the mechanisms we have in place include the following:

Gas Utility Jurisdiction	Cost Recovery Mechanisms							
	DSM/ Energy Efficiency	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Gas Cost	Billing Determinant Adjustment	Revenue Decoupling
Arkansas Gas	☑	☑		☑		☑	☑	
Colorado Gas	☑					☑		
Colorado Gas Dist.	☑					☑		
RMNG	N/A	☑	N/A	N/A	N/A	N/A	N/A	N/A
Iowa Gas	☑	☑				☑		
Kansas Gas		☑	☑	☑	☑	☑		
Nebraska Gas		☑	☑			☑		
Nebraska Gas Dist.		☑	☑					
Wyoming Gas [(a)]	☑					☑		
Wyoming Gas Dist.						☑		☑

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(a) DSM/Energy Efficiency is only applicable to Cheyenne Light.

See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current natural gas rate activity.

Operating Statistics

2016 includes results from the acquired SourceGas utilities starting February 12, 2016.

	Revenue (in thousands)			Gross Margin [(a)] (in thousands)			Quantities Sold and Transported (Dth)		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Residential	$ 567,785	$ 499,852	$ 433,106	$ 276,858	$ 255,626	$ 228,512	65,352,164	54,645,598	49,390,451
Commercial	214,718	197,054	162,547	82,529	78,249	67,375	30,753,361	27,315,871	24,037,861
Industrial	26,466	24,454	21,245	7,056	6,226	5,601	6,309,211	5,855,053	5,737,430
Other [(b)]	(7,899)	8,647	12,694	(7,899)	8,647	12,694	—	—	—
Total	801,070	730,007	629,592	358,544	348,748	314,182	102,414,736	87,816,522	79,165,742
Transportation and Transmission	141,854	135,824	139,490	141,850	135,824	139,282	148,299,003	141,600,080	126,927,565
Total Regulated	942,924	865,831	769,082	500,394	484,572	453,464	250,713,739	229,416,602	206,093,307
Non-regulated Services	82,383	81,799	69,261	62,760	53,455	32,714	—	—	—
Total Revenue, Gross Margin and Quantities Sold	$1,025,307	$ 947,630	$ 838,343	$ 563,154	$ 538,027	$ 486,178	250,713,739	229,416,602	206,093,307

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(a) Non-GAAP measure.
(b) Other revenue and Gross Margin in 2018 reflects the impact of revenue reserved in accordance with the TCJA.

	Revenue (in thousands)			Gross Margin [a] (in thousands)			Quantities Sold & Transported (Dth)		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Arkansas	$ 176,660	$ 153,691	$ 106,958	$ 100,917	$ 94,007	$ 69,840	30,931,390	26,491,537	19,177,438
Colorado	188,002	180,852	153,003	99,851	100,718	86,016	29,857,063	28,436,744	23,656,891
Nebraska	278,969	252,631	244,992	164,513	154,259	146,831	81,658,938	73,890,509	67,796,021
Iowa	161,843	143,446	130,776	68,384	66,619	64,170	40,668,682	37,013,645	35,383,990
Kansas	112,306	105,576	100,670	55,226	53,841	54,247	31,387,672	28,251,947	26,463,314
Wyoming	107,527	111,434	101,944	74,263	68,583	65,074	36,209,994	35,332,220	33,615,653
Total Revenue, Gross Margin and Quantities Sold	$1,025,307	$ 947,630	$ 838,343	$ 563,154	$ 538,027	$ 486,178	250,713,739	229,416,602	206,093,307

(a) Non-GAAP measure.

Customers at End of Year	2018	2017	2016
Residential	821,624	806,744	800,980
Commercial [a]	82,498	86,461	84,049
Industrial	2,221	2,214	2,050
Transportation/Other	147,550	146,839	143,673
Total Customers at End of Year	1,053,893	1,042,258	1,030,752

(a) The decrease is 2018 is due to customer class reclassification to residential at our Colorado Gas utilities.

Customers at End of Year	2018	2017	2016
Arkansas	171,978	169,303	166,512
Colorado	186,759	181,876	177,394
Nebraska	291,723	290,264	289,653
Iowa	158,485	157,444	156,014
Kansas	114,840	114,082	112,957
Wyoming	130,108	129,289	128,222
Total Customers at End of Year	1,053,893	1,042,258	1,030,752

Utility Regulation Characteristics

State Regulations

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. As of December 31, 2018, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard that has two components: (i) electric resource standards and (ii) a 2% maximum annual retail rate impact for compliance with the electric resource standards. The electric resource standards require our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 20% of retail sales from 2015 to 2019; and (ii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) is limited to 2%. The standard encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We are currently in compliance with these standards.

  On April 25, 2018, Colorado Electric received approval from the CPUC to contract with Black Hills Electric Generation to purchase 60 MW of wind energy through a 25-year PPA. The Busch Ranch II wind project is currently under construction and is expected to be in service by the end of 2019. This renewable energy will enable Colorado Electric to comply with Colorado's Renewable Energy Standard. This renewable energy project was originally submitted in response to Colorado Electric's electric resource plan filed June 3, 2016, which also provides for additional small solar and community solar gardens as part of the compliance plan.

  On November 7, 2016, Colorado Electric took ownership of Peak View, a $109 million, 60 MW wind project located near Colorado Electric's Busch Ranch I Wind Farm. Peak View achieved commercial operation on November 7, 2016. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. The CPUC's settlement agreement provides for recovery of the costs of the project through Colorado Electric's Energy Cost Adjustments and Renewable Energy Standard Surcharge for 10 years, after which, Colorado Electric can propose base rate recovery. Colorado Electric will be required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility.

- Montana. In 2005, Montana established a renewable portfolio standard that requires public utilities to obtain a percentage of their retail electricity sales from eligible renewable resources. In March 2013, South Dakota Electric filed a petition with the MTPSC requesting a waiver of the renewable portfolio standards primarily due to exceeding the applicable "cost cap" included in the standards. In March 2013, the Montana Legislature adopted legislation that had the effect of excluding South Dakota Electric from all renewable portfolio standard requirements under State Senate Bill 164, primarily due to the very low number of customers South Dakota Electric has in Montana and the relatively high cost of meeting the renewable requirements.

- South Dakota. South Dakota has adopted a renewable portfolio objective that encourages, but does not mandate utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015.

- Wyoming. Wyoming currently has no renewable energy portfolio standard.

Absent a specific renewable energy mandate in the territories we serve, our current strategy is to prudently incorporate renewable energy into our resource supply. Mandatory portfolio standards have increased and would likely continue to increase the power supply costs of our Electric Utilities' operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery of the costs we pay to be in compliance with standards or objectives. We cannot at this time reasonably forecast the potential costs associated with any new renewable energy standards that have been or may be proposed at the federal or state level.

Federal Regulation

Energy Policy Act. Black Hills Corporation is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and holding companies regulated by FERC under the Federal Power Act and PUHCA 2005.

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, and terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public Electric Utilities' subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities, Black Hills Colorado IPP and Black Hills Wyoming are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. Our Electric Utilities own and operate FERC-jurisdictional interstate transmission facilities and provide open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

The Federal Power Act authorizes FERC to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of a utility holding company. As a utility holding company with a centralized service company subsidiary, BHSC, we are subject to FERC's authority under PUHCA 2005.

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2018, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of approximately 283 MW.

We produce electric power from our generating plants and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell a substantial majority of our non-regulated generating capacity under contracts having terms greater than one year.

As of December 31, 2018, the power plant ownership interests held by our Power Generation segment include:

Power Plants	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	In Service Date
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation [(a)]	Gas	Pueblo, Colorado	50.1%	200.0	2012
Busch Ranch I	Wind	Pueblo, Colorado	50.0%	14.5	2012
				283.4	

(a) Black Hills Colorado IPP owns and operates this facility. This facility provides capacity and energy to Colorado Electric under a 20-year PPA with Colorado Electric. This PPA is accounted for as a capital lease on the accompanying Consolidated Financial Statements.

Black Hills Wyoming - Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant and MEAN owns the remaining 23.5%. We sell 60 MW of unit-contingent capacity and energy from this plant to Wyoming Electric under a PPA that expires on December 31, 2022. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical to do so. The PPA includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. See the purchased power discussion within the Electric Utilities segment above about Wyoming Electric's 2018 integrated resource plan which included a recommendation to the WPSC to acquire Wygen I.

Black Hills Colorado IPP - Pueblo Airport Generation. The Pueblo Airport Generating Station consists of two 100 MW combined-cycle gas-fired power generation plants located at a site shared with Colorado Electric. The plants commenced operation on January 1, 2012 and the assets are accounted for as a capital lease under a 20-year PPA with Colorado Electric, which expires on December 31, 2031. Under the PPA with Colorado Electric, any excess capacity and energy shall be for the benefit of Colorado Electric.

Black Hills Electric Generation (BHEG) - Busch Ranch I. On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest in the 29 MW Busch Ranch I Wind Farm, previously owned by AltaGas. Black Hills Electric Generation will provide its share of energy from the wind farm to Colorado Electric through a new PPA which has the same terms as the PPA it replaces that Colorado Electric had with AltaGas, expiring in October 2037.

Third Party Noncontrolling Interest in Subsidiary

In 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third party buyer. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes. The operating results for Black Hills Colorado IPP remain consolidated with Black Hills Electric Generation, as Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest.

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) [(a)]	2018	2017	2016
Sold			
Black Hills Colorado IPP [(b)]	1,000,577	943,618	1,223,949
Black Hills Wyoming [(c)]	582,938	645,810	644,564
Black Hills Electric Generation	5,873	—	—
Total Sold	1,589,388	1,589,428	1,868,513
Generated			
Black Hills Colorado IPP [(b)]	1,000,577	943,618	1,223,949
Black Hills Wyoming [(c)]	501,945	577,124	543,546
Black Hills Electric Generation	5,873	—	—
Total Generated	1,508,395	1,520,742	1,767,495
Purchased			
Black Hills Wyoming	83,213	69,377	85,993
Total Purchased	83,213	69,377	85,993

(a) Company use and losses are not included in the quantities sold, generated and purchased.
(b) The decrease in 2017 was driven by the joint dispatch agreement Colorado Electric joined in 2017. See details of this agreement above in the Electric Utilities segment.
(c) The decrease in 2018 was driven by a planned outage at Wygen I.

Operating Agreements. Our Power Generation segment has the following material operating agreements:

- Economy Energy PPA and other ancillary agreements
    - Black Hills Wyoming has ancillary agreements with the City of Gillette, Wyoming to operate CTII, and provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreements include a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.
- Operating and Maintenance Services Agreement
    - In conjunction with the sale of the noncontrolling interest on April 14, 2016, an operating and maintenance services agreement was entered into between Black Hills Electric Generation and Black Hills Colorado IPP. This agreement sets forth the obligations and responsibilities of Black Hills Electric Generation as the operator of the generating facility owned by Black Hills Colorado IPP. This agreement is in effect from the date of the noncontrolling interest purchase and remains effective as long as the operator or one of its affiliates is responsible for managing the generating facilities in accordance with the noncontrolling interest agreement, or until termination by owner or operator.
- Shared Services Agreements
    - South Dakota Electric, Wyoming Electric and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.
    - Black Hills Colorado IPP and Colorado Electric are parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric's assets.
    - Black Hills Colorado IPP, Wyoming Electric and South Dakota Electric are parties to a Spare Turbine Use Agreement, whereby Black Hills Colorado IPP charges South Dakota Electric and Wyoming Electric a monthly fee for the availability of a spare turbine to support the operation of Cheyenne Prairie Generating Station.
    - Black Hills Colorado IPP and Black Hills Wyoming receive certain staffing and management services from BHSC.
- Jointly Owned Facilities
    - Black Hills Wyoming and MEAN are parties to a shared joint ownership agreement, whereby Black Hills Wyoming charges MEAN for administrative services, plant operations and maintenance on its share of the Wygen I generating facility over the life of the plant.
    - Black Hills Electric Generation and Colorado Electric both own 50% of the Busch Ranch I Wind Farm. Black Hills Electric Generation purchased its 50% share in Busch Ranch I from AltaGas on December 11, 2018. See details of the PPA and ownership agreement discussed previously in the Electric Utilities segment.

Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for independent power producers in some regions.

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own three EWGs: Wygen I, 200 MW (two 100 MW combined-cycle gas-fired units) at the

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Pueblo Airport Generating Station, and Black Hills Electric Generation's interest in Busch Ranch I. Our EWGs were granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates.

Mining Segment

Our Mining segment operates through our WRDC subsidiary. We surface mine, process and sell primarily low-sulfur sub-bituminous coal at our mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 4.1 million tons of coal in 2018.

During our surface mining operations, we strip and store the topsoil. We then remove the overburden (earth and rock covering the coal) with heavy equipment. Removal of the overburden typically requires drilling and blasting. Once the coal is exposed, we drill, fracture and systematically remove it, using front-end loaders and conveyors to transport the coal to the mine-mouth generating facilities. We reclaim disturbed areas as part of our normal mining activities by back-filling the pit with overburden removed during the mining process. Once we have replaced the overburden and topsoil, we reestablish vegetation and plant life in accordance with our approved post-mining topography plan.

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has in recent years trended upwards. The overburden ratio at December 31, 2018 was 2.20 which increased from the prior year as we continued mining in areas with higher overburden. We expect our stripping ratio to be approximately 2.26 by the end of 2019 as we mine in areas with comparable overburden.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between April 30, 2019 and September 30, 2025 and the state lease expires on August 1, 2023. The duration of the leases varies; however, the lease terms generally are extended to the exhaustion of economically recoverable reserves, as long as active mining continues. We pay federal and state royalties of 12.5% of the selling price of all coal. As of December 31, 2018, we estimated our recoverable coal reserves to be approximately 189 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering studies. The recoverable coal reserve life is equal to approximately 46 years at the current production levels. Our recoverable coal reserve estimates are periodically updated to reflect past coal production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable coal reserves include reserves that can be economically and legally extracted at the time of their determination. We use various assumptions in preparing our estimate of recoverable coal reserves. See Risk Factors under Mining for further details.

Substantially all of our coal production is currently sold under contracts to:

- South Dakota Electric for use at the 90 MW Neil Simpson II plant to which we sell approximately 500,000 tons of coal each year. This contract is for the life of the plant;

- Wyoming Electric for use at the 95 MW Wygen II plant to which we sell approximately 550,000 tons of coal each year. This contract is for the life of the plant;

- The 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by South Dakota Electric. PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustments for planned outages. South Dakota Electric is also obligated to purchase a minimum of 0.375 million tons of coal per year for its 20% share of the power plant, subject to adjustments for planned outages. This contract expires December 31, 2022;

- The 110 MW Wygen III power plant owned 52% by South Dakota Electric, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons of coal each year. This contract expires June 1, 2060;

- The 90 MW Wygen I power plant owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons of coal each year. This contract expires June 30, 2038; and

- Certain regional industrial customers served by truck to which we sell a total of approximately 150,000 tons of coal each year. These contracts have terms of one to five years.

Our Mining segment sells coal to South Dakota Electric and Wyoming Electric for all of their requirements under cost-based agreements that regulate earnings from these affiliate coal sales to a specified return on our coal mine's cost-depreciated investment base. The return calculated annually is 400 basis points above A-rated utility bonds applied to our Mining investment base. South Dakota Electric made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for South Dakota Electric's operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant and through June 1, 2060, for Wygen III. The agreement with Wyoming Electric provides coal for the life of the Wygen II plant.

The price of unprocessed coal sold to PacifiCorp for the Wyodak plant is determined by the coal supply agreement described above. The agreement includes a price adjustment in 2019. The price adjustment essentially allows us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustment is based on the market price of coal plus considerations for the avoided costs of rail transportation and a coal unloading facility, which PacifiCorp would have to incur if it purchased coal from another mine. In addition, the agreement also provides for the monthly escalation of coal price based on an escalation factor.

The current contract price ($19.08 per ton as of December 2018) is comprised of three components: 1) avoided transportation costs (approximately 20% of current price); 2) avoided costs of a coal unloading facility (approximately 30% of current price); and 3) a rolling 12-month average of the Coal Daily spot market price of 8,400 Btu Powder River Basin coal (approximately 50% of current price). With respect to the 2019 coal price re-opener, we expect the transportation and unloading costs to escalate slightly. The current trailing 12-month spot price of 8,400 Btu Powder River Basin coal, ending March 2019, is approximately one dollar less than the price used for the 2014 price re-opener.

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement using a base price that includes price escalators and quality adjustments through June 30, 2038 and includes actual cost per ton plus a margin equal to the yield for Moody's A-Rated 10-Year Corporate Bond Index plus 400 basis points with the base price being adjusted on a 5-year interval. The agreement stipulates that WRDC will supply coal to the 90 MW Wygen I plant through June 30, 2038.

Competition. Our primary strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically, off-site sales have been to consumers within a close proximity to the mine. Rail transport market opportunities for WRDC coal are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC coal mine is served by only one railroad, resulting in less competitive transportation rates. Management continues to explore the limited market opportunities for our product through truck transport.

Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental considerations and availability affect the overall demand for coal as a fuel.

Environmental Matters. We are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. See Environmental Matters section for further information.

Mine Reclamation. Reclamation is required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five-year mining permit issued by the State of Wyoming. In 2016, that five-year permit was re-issued. Based on extensive reclamation studies, we have accrued approximately $16 million for reclamation costs as of December 31, 2018. Mining regulatory requirements continue to increase, which impose additional cost on the mining process.

Environmental Matters

South Dakota and Wyoming Power Generation. Based on current regulations, technology and plans, the following table contains our current estimates of capital expenditures expected to be incurred over the next three years to comply with current environmental laws and regulations as described below, including regulations that cover water, air, soil and other pollutants, but excluding plant closures and the cost of new generation. The ultimate cost could be significantly different from the amounts estimated.

Environmental Expenditure Estimates		Total (in thousands)
2019	$	1,503
2020		1,088
2021		710
Total	$	3,301

Methane Rules (Greenhouse Gas Emissions). The EPA and the State of Colorado have implemented strict regulatory requirements on hydrocarbon and methane emissions associated with natural gas gathering and transmission systems. The BLM repealed similar hydrocarbon and methane emissions reductions it previously established under the Methane Rule (Venting and Flaring rule). Presently, we have four facilities in our Colorado natural gas transmission operations affected by the hydrocarbon and methane reduction rules.

Our operations are currently in compliance with both EPA and State of Colorado rules. Future modifications to our gathering and transmissions systems are anticipated to trigger EPA methane rules. We plan to develop a corporate-wide methane control strategy to address GHG emissions from our natural gas operations as we anticipate this will be a requirement in future rule-making efforts.

Water Issues. Our facilities are subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the Clean Water Act and govern overall water/wastewater discharges through EPA's surface water discharge and storm water permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. The EPA proposed effluent limitation guidelines and standards on June 7, 2013 and published the final rule on November 3, 2015. In 2017, the EPA postponed the implementation of the rule and set a timeline in 2018 to revise the rule. To date, the rule has not been sent for publication. This rule will have an impact on the Wyodak Plant. Until the EPA issues the rule for publication, we can not quantify what the potential impact may be on the Wyodak Plant. The terms of this new regulation may impact the next permit renewal, which will be in 2020.

Short-term Emission Limits. The EPA and State Air Quality Programs implemented short-term emission limits for coal and natural gas-fired generating units during normal and start-up operating scenarios for SO_2, NO_x and Opacity. The limits pertain to emissions during start-up periods and upset conditions such as mechanical malfunctions. State and federal regulatory agencies typically excuse short-term emissions exceedances if they are reported and corrected immediately or if it occurs during start-up.

We proactively manage this requirement through maintenance efforts and installing additional pollution control systems to control SO_2 emission short-term excursions during start-up. These actions have nearly eliminated our short-term emission limit compliance risk while plant availability remained above 90% for all four of our coal-fired plants. To eliminate the remaining potential for exceedances, an innovative trip logic mechanism was implemented to shut the power plant down if a predicted emission limit is to be exceeded. Similar efforts have been taken and similar results achieved with our natural gas fired combustion turbine sites as well.

Regional Haze (Impacts to the Wyodak Power Plant). The EPA Regional Haze rule was promulgated to improve visibility in our National Parks and Wilderness Areas. The State of Wyoming proposed controls in its Regional Haze State Implementation Plan (SIP) which allowed PacifiCorp to install low-NO_x burners in the Wyodak Plant, of which South Dakota Electric owns 20%. The EPA did not agree with the State of Wyoming's determination and overruled it in a Federal Implementation Plan (FIP). The State of Wyoming and other interested parties are challenging the EPA's determination. If the challenge is unsuccessful, additional capital investment would be necessary to bring the Wyodak Plant into compliance. Our 20% share of this capital investment for the facility would be approximately $40 million if PacifiCorp is required to install a Selective Catalytic Reactor for NO_x control. The case is currently held in abeyance at the 10th circuit court while a settlement reached between one of the interested parties and the EPA is implemented.

Mining. Operations at the WRDC mine must regularly address issues related to the proximity of the mine disturbance boundary to the City of Gillette, and to residential and industrial properties. Homeowner complaints and challenges to the permits may occur as mining operations move closer to residential areas. Specific concerns could include damage to wells, fugitive dust emissions, vibration and an emissions cloud from blasting.

Former Manufactured Gas Plants (FMGP). Federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. Our Gas Utilities are managing FMGP sites in Iowa and Nebraska. We are currently in discussions with EPA, state regulators, and/or other third-parties to determine the ultimate resolution to these sites. As of December 31, 2018, we are working on the site in Council Bluffs, Iowa, and the site in McCook, Nebraska. We have been contacted by a third-party who indicated it intends to manage and pay for the clean-up at the McCook Nebraska site.

Affordable Clean Energy Rule. The EPA was directed to repeal, revise, and replace the Clean Power Plan rule. On August 31, 2018, the EPA published the proposed Affordable Clean Energy rule. This rule focuses on heat-rate improvements on coal-fired boiler units and poses significantly less risk than the Clean Power Plan. The 60-day comment period has ended and the EPA is reviewing comments prior to issuing a final rule.

OSM Coal Combustion Residual Rule (CCR). The EPA issued the CCR which is currently effective and establishes requirements to protect surface and groundwater from impacts of coal ash impoundments. WRDC is exempt from the EPA CCR because coal ash is used for backfill reclamation in the areas previously mined. The current administration has not pursued further modification of the CCR.

Environmental risk changes constantly with the implementation of new or modified regulations, changing stakeholder interests and needs, and through the introduction of innovative work practices and technologies. We assess risk annually and develop mitigation strategies to successfully and responsibly manage and ensure compliance across the enterprise. For additional information on environmental matters, see Item 1A and Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Other Properties

In addition to the facilities previously disclosed in Items 1 and 2, we own or lease several facilities throughout our service territories. Our owned facilities are as follows:

- In Rapid City, South Dakota, we have a 220,000 square foot corporate headquarters building, Horizon Point, which was completed in the fourth quarter of 2017.
- In Arkansas, Nebraska, Iowa, Colorado, Kansas and Wyoming we own various office, service center, storage, shop and warehouse space totaling over 805,000 square feet utilized by our Gas Utilities.
- In South Dakota, Wyoming, Colorado and Montana we own various office, service center, storage, shop and warehouse space totaling approximately 240,000 square feet utilized by our Electric Utilities and Mining segments.

In addition to our owned properties, we lease 194,361 square feet of properties within our service areas.

Substantially all of the tangible utility properties of South Dakota Electric and Wyoming Electric are subject to liens securing first mortgage bonds issued by South Dakota Electric and Wyoming Electric, respectively.

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Employees

At December 31, 2018, we had 2,863 full-time employees in continuing operations. Approximately 25% of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At December 31, 2018, approximately 23% of our total employees and 18% of our Electric and Gas Utilities employees were eligible for regular or early retirement.

The following table sets forth the number of employees included in continuing operations:

	Number of Employees
Corporate	499
Electric Utilities and Gas Utilities	2,301
Mining and Power Generation	63
Total	2,863

At December 31, 2018, certain employees of our Electric Utilities and Gas Utilities were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
South Dakota Electric	128	IBEW Local 1250	March 31, 2022
Wyoming Electric	42	IBEW Local 111	June 30, 2019
Colorado Electric	103	IBEW Local 667	April 15, 2023
Iowa Gas	106	IBEW Local 204	July 31, 2020
Kansas Gas	19	Communications Workers of America, AFL-CIO Local 6407	December 31, 2019
Nebraska Gas	99	IBEW Local 244	March 13, 2022
Nebraska Gas (a)	146	CWA Local 7476	October 30, 2019
Wyoming Gas (a)	85	CWA Local 7476	October 30, 2019
Total	728		

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(a) In the 2016 negotiations with the CWA Local 7476, the union agreed to disclaim their interest in Colorado Gas employees and to split the remaining bargaining unit into two distinct bargaining units, Nebraska Gas and Wyoming Gas.

ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. The following risk factors and other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company. These important factors and other matters discussed herein could cause our future actual results or outcomes to differ materially.

OPERATING RISKS

Our financial performance depends on the successful operation of our facilities. If the risks involved in our operations are not appropriately managed or mitigated, our operations may not be successful and this could adversely affect our results of operations.

Operating electric generating facilities, the coal mine and electric and natural gas transmission and distribution systems involves risks, including:

- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted physically, mechanically, or with cyber means, our ability to sell or deliver product and satisfy our contractual obligations may be hindered;

- Interruptions to supply of fuel and other commodities used in generation and distribution. Our utilities purchase fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather and environmental regulations, which could limit our utilities' ability to operate their facilities;

- Electricity is dangerous for employees and the general public should they come in contact with power lines or electrical service facilities and equipment. Natural conditions and other disasters such as wind, lightning and winter storms can cause wildfires, pole failures and associated property damage and outages;

- Operating hazards such as leaks, mechanical problems and accidents, including explosions affecting our natural gas distribution system, which could impact public safety, reliability and customer confidence;

- Operational limitations imposed by environmental and other regulatory requirements;

- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak Plant;

- Labor relations. Approximately 25% of our employees are represented by a total of eight collective bargaining agreements;

- Our ability to transition and replace our retirement-eligible utility employees. At December 31, 2018, approximately 18% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement;

- Inability to recruit and retain skilled technical labor; and

- Disruption in the functioning of our information technology and network infrastructure which are vulnerable to disability, failures and unauthorized access. If our information technology systems were to fail and we were unable to recover in a timely manner, we would be unable to fulfill critical business functions.

Changes in the interpretation of the Tax Cuts and Jobs Act ("TCJA") could adversely affect us.

On December 22, 2017, the TCJA was signed into law, significantly reforming the U.S. Internal Revenue Code. The TCJA, among other things, includes a decrease in the U.S. federal corporate tax rate from 35% to 21%, imposes significant additional limitations on the deductibility of interest, allows for the expensing of capital expenditures, and modifies or repeals many business deductions and credits. The new tax law contains several provisions that impacted our 2017 and 2018 financial results.

The TCJA includes provisions limiting interest deductibility in certain circumstances. While we expect to maintain deductibility of interest expense, the lower tax rate reduces the tax benefits associated with interest deductibility on holding company debt that is not recovered in the regulatory construct.

If there are future changes and amendments to the TCJA, and if we are unable to obtain reasonable outcomes with our utility regulators in passing future benefits of the TCJA back to customers, or if our interpretations on the provisions of depreciation or interest deductibility in the TCJA change, our results of operations, financial position or cash flows could be materially impacted.

Construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve significant risks which could reduce profitability.

The construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve many risks, including:

- The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals;

- Contractual restrictions upon the timing of scheduled outages;

- The cost of supplying or securing replacement power during scheduled and unscheduled outages;

- The unavailability or increased cost of equipment;

- The cost of recruiting and retaining or the unavailability of skilled labor;
- Supply interruptions, work stoppages and labor disputes;
- Increased capital and operating costs to comply with increasingly stringent environmental laws and regulations;
- Opposition by members of public or special-interest groups;
- Weather interferences;
- Availability and cost of fuel supplies;
- Unexpected engineering, environmental and geological problems; and
- Unanticipated cost overruns.

The ongoing operation of our facilities involves many of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, including newer environmental emission control technology. Any of these risks could cause us to operate below expected capacity levels, which in turn could reduce revenues, increase expenses or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

Operating results can be adversely affected by variations from normal weather conditions.

Our utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, respectively. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters therefore could have an adverse effect on our results of operations, financial position or cash flows.

Our businesses are located in areas that could be subject to seasonal natural disasters such as severe snow and ice storms, flooding and wildfires. These events could result in interruption of our business, damage to our property such as power lines and substations, and repair and clean-up costs. We may not be able to recover the costs incurred in restoring transmission and distribution property following these natural disasters through a change in our regulated rates thereby resulting in a negative impact on our results of operations, financial position and cash flows.

Our Mining operations are subject to operating risks that are beyond our control which could affect our profitability and production levels. Our surface mining operations could be disrupted or materially affected due to adverse weather or natural disasters such as heavy snow, strong winds, rain or flooding.

Prices for some of our products and services as well as a portion of our operating costs are volatile and may cause our revenues and expenses to fluctuate significantly.

A portion of our net income is attributable to sales of wholesale and off-system electricity and natural gas. Energy prices are influenced by many factors outside our control, including, among other things, fuel prices, transmission constraints, supply and demand, weather, general economic conditions, and the rules, regulations and actions of system operators in those markets. As a result, wholesale power markets may be subject to significant, unpredictable price fluctuations over relatively short periods of time.

Our Mining operations require reliable supply of replacement parts, explosives, fuel, tires and steel-related products. If the cost of these increase significantly, or if sources of supplies and mining equipment become unavailable to meet our replacement demands, our productivity and profitability could be lower than our current expectations.

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, emerging technologies or responses to price increases.

Our revenues, results of operations and financial condition are impacted by demand in our service territories. Customer growth and usage may 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 customers' disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us would decline. Such developments could affect the price of energy and delivery of energy, 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. Each of these factors could materially affect our results of operations, financial position or cash flows.

Our operations rely on storage and transportation assets owned by third parties to satisfy our obligations.

Our Electric Utilities, Gas Utilities and Power Generation segments rely on pipeline companies and other owners of gas storage facilities to deliver natural gas to customers, to supply our natural gas-fired power plants and to hedge commodity costs. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered. As a result, we may be responsible for damages incurred by our counterparties, such as the additional cost of acquiring alternative supply at then-current market rates, or for penalties imposed by state regulatory authorities.

Our utilities are subject to pipeline safety and system integrity laws and regulations that may require significant capital expenditures or significant increases in operating costs.

Compliance with pipeline safety and system integrity laws and regulations, or future changes in these laws and regulations, may result in increased capital, operating and other costs which may not be recoverable in a timely manner from customers through rates. Failure to comply may result in fines, penalties, or injunctive measures that would not be recoverable from customers through rates and could result in a material impact on our results of operations, financial position or cash flows.

Our energy production, transmission and distribution activities, and our storage facilities for our natural gas involve numerous risks that may result in accidents and other catastrophic events that could give rise to additional costs and cause a substantial loss to us.

Inherent in our natural gas and electricity transmission and distribution activities, as well as in our transportation and storage of natural gas and our Mining operations, are a variety of hazards and operating risks, such as leaks, blowouts, fires, releases of hazardous materials, explosions and operational problems. These events could impact the safety of employees or others and result in injury or loss of human life, and cause significant damage to property or natural resources (including public lands), environmental pollution, impairment of our operations and substantial financial losses to us. Particularly for our transmission and distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the damages resulting from any such events could be substantial. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events not fully covered by our insurance could have a material adverse effect on our financial position, results of operations or cash flows.

Threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our businesses, or the businesses of third parties, may impact our operations in unpredictable ways.

Terrorist acts or other similar events could harm our businesses by limiting their ability to generate, purchase or transmit power, deliver natural gas and by delaying their development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure our assets and could adversely affect our operations by contributing to disruption of supplies and markets for natural gas, oil and other fuels. They could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs. These types of events could materially adversely affect our financial results. In addition, these types of events could require significant management attention and resources and could adversely affect our reputation among customers and the public.

A cyber attack may disrupt our operations, or lead to a loss or misuse of confidential and proprietary information and create a potential liability.

We use and operate sophisticated control, SCADA, and information technology systems and network infrastructure. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees. Cyber attacks targeting our electronic control systems used at our generating facilities and for electric and gas distribution systems, could result in a full or partial disruption of our electric and/or gas operations. Cyber attacks targeting other key information technology systems, including our third-party vendors' information systems, could further add to a full or partial disruption of our operations. Any disruption of these operations could result in a loss of service to customers and a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. Any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data as a result of a cyber attack could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others.

We have instituted security measures and safeguards to protect our operational systems and information technology assets, including certain safeguards required by FERC. The security measures and safeguards we have implemented may not always be effective due to the evolving nature and sophistication of cyber attacks. Despite our implementation of security measures and safeguards, all of our information technology systems are vulnerable to disability, failures or unauthorized access, including cyber attacks. If our information technology systems or our third-party vendors' systems were to fail or be breached by a cyber attack or a computer virus and be unable to recover in a timely way, we would be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised which could have a material adverse effect not only on our financial results, but on our public reputation as well.

Increased risks of regulatory penalties could negatively impact our results of operations, financial position or liquidity.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Agencies that historically sought voluntary compliance, or issued non-monetary sanctions, now employ mandatory civil penalty structures for regulatory violations. The FERC, NERC, CFTC, EPA, OSHA, SEC and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which could have a material adverse effect on our operations and/or our financial results.

Certain Federal laws, including the Migratory Bird Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for non-permitted activities that result in harm to or harassment of certain protected animals, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly transmission, generation, wind and pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures.

Our current or future development and expansion activities may not be successful, which could impair our ability to execute our growth strategy.

Execution of our growth plan is dependent on successful ongoing and future development and expansion activities. We can provide no assurance that we will be able to complete development projects or expansion activities we undertake or continue to develop attractive opportunities for growth. Factors that could cause our development and expansion activities to be unsuccessful include:

- Our inability to obtain required governmental permits;
- Our inability to complete capital projects in a timely manner;
- Our inability to secure just and reasonable utility rates through regulatory proceedings;
- Our inability to obtain financing on acceptable terms, or at all;
- The possibility that one or more credit rating agencies would downgrade our issuer credit rating to below investment grade, thus increasing our cost of doing business;
- Our inability to attract and retain management or other key personnel;
- Our inability to negotiate acceptable construction, fuel supply, power sales or other material agreements;
- Reduced growth in the demand for utility services in the markets we serve;
- Changes in federal, state, local or tribal laws and regulations, particularly those which would make it more difficult or costly to fully develop our coal reserves or our power generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints;
- Competition within our industry and with producers of competing energy sources; and
- Changes in tax rates and policies.

<u>Utilities</u>

Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request in the future, or may determine that amounts passed through to customers were not prudently incurred and therefore are not recoverable.

Our regulated Electric Utilities and Gas Utilities are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs, including our direct and allocated borrowing and debt service costs, to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

To some degree, each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs) without having to file a rate review. To the extent we are able to pass through such costs to our customers, and a state public utility commission subsequently determines that such costs should not have been paid by the customers, we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could adversely affect our results of operations, financial position or cash flows.

If market or other conditions adversely affect operations or require us to make changes to our business strategy in any of our utility businesses, we may be forced to record a non-cash goodwill impairment charge. Any significant impairment of our goodwill related to these utilities would cause a decrease in our assets and a reduction in our net income and shareholders' equity.

We had approximately $1.3 billion of goodwill on our consolidated balance sheets as of December 31, 2018. A substantial portion of the goodwill is related to the SourceGas Acquisition and the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets, net income and shareholders' equity. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in economic conditions and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

Municipal governments may seek to limit or deny franchise privileges which could inhibit our ability to secure adequate recovery of our investment in assets subject to condemnation.

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation.

<u>**Mining**</u>

If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, our costs could be significantly greater than anticipated or be incurred sooner than anticipated.

We conduct surface mining operations that are subject to operations, reclamation and closure standards. We estimate our total reclamation liabilities based on permit requirements, engineering studies and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by our management and engineers and by government regulators. The estimated liability can change significantly if actual costs vary from our original assumptions or if government regulations change significantly. GAAP requires that asset retirement obligations be recorded as a liability based on fair value, which reflects the present value of the estimated future cash flows. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates. The resulting estimated reclamation obligations could change significantly if actual amounts or the timing of these expenses change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial position.

Estimates of the quality and quantity of our coal reserves may change materially due to numerous uncertainties inherent in three-dimensional structural modeling, and any inaccuracies in interpretation or modeling could materially affect the estimated quantity and quality of our reserves.

The process of estimating coal reserves is uncertain and requires interpretations and modeling. Significant inaccuracies in interpretation or modeling could materially affect the quantity and quality of our reserve estimates. The accuracy of reserve estimates is a function of engineering and geological interpretation, conditions encountered during actual reserve recovery and undetected deposit anomalies. Variance from the assumptions used and drill hole modeling density could result in additions or deletions from our volume estimates. In addition, future environmental, economic or geologic changes may occur or become known that require reserve revisions either upward or downward from prior reserve estimates.

FINANCING RISKS

Our credit ratings could be lowered below investment grade in the future. If this were to occur, it could impact our access to capital, cost of capital and other operating costs.

Our issuer credit rating is Baa2 (Stable outlook) by Moody's; BBB+ (Stable outlook) by S&P; and BBB+ (Stable outlook) by Fitch. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt and to complete new financings on reasonable terms, or at all. A credit rating downgrade, particularly to a sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts or trades. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities.

Derivatives regulations could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared resulting in a requirement to post cash collateral (commonly referred to as "margin") for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users such as utilities and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use natural gas derivative instruments for our hedging activities for our Gas and Electric Utilities' operations. We may also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. As a result of Dodd-Frank regulations promulgated by the CFTC, we may be required to post collateral for certain swap transactions we enter into. In addition, our exchange-traded futures contracts are subject to futures margin posting requirements, which could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results due to accounting requirements associated with such activities.

We use various financial contracts and derivatives, including futures, forwards, options and swaps to manage commodity price and financial market risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP does not always match up with the gains or losses on the commodities being hedged. The difference in accounting may result in volatility in reported results, even though the expected profit margin may be essentially unchanged from the dates the transactions were consummated.

Our use of derivative financial instruments could result in material financial losses.

From time to time, we have sought to limit a portion of the potential adverse effects resulting from changes in commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Market performance or changes in other assumptions could require us to make significant unplanned contributions to our pension plans and other postretirement benefit plans. Increasing costs associated with our defined benefit retirement plans may adversely affect our results of operations, financial position or cash flows.

As discussed in Note 18 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan (the pension plan is closed to new employees and frozen for certain employees who did not meet age and service based criteria) and several defined post-retirement healthcare plans and non-qualified retirement plans that cover certain eligible employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to these plans. These estimates and assumptions may change based on actual return on plan assets, changes in interest rates and any changes in governmental regulations.

We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries.

As a holding company, our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital, equity or debt service funds.

There is no assurance as to the amount, if any, of future dividends because they depend on our future earnings, capital requirements and financial condition and are subject to declaration by the Board of Directors. Our operating subsidiaries have certain restrictions on their ability to transfer funds in the form of dividends or loans to us. See "Liquidity and Capital Resources" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

We may be unable to obtain financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings, and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in commodity or electricity prices, and general economic and market conditions.

In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

National and regional economic conditions may cause increased counterparty credit risk, late payments and uncollectible accounts, which could adversely affect our results of operations, financial position or cash flows.

A future recession may lead to an increase in late payments from retail, commercial and industrial utility customers, as well as from our non-utility customers. If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

Our ability to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. Our insurance coverage may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting insurance businesses, international, national, state or local events, as well as the financial condition of insurers. Insurance coverage may not continue to be available at all, or at rates or on terms similar to those presently available to us. A loss for which we are not fully insured could materially and adversely affect our financial results. Our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which the Company may be subject, including but not limited to environmental hazards, fire-related liability from natural events or inadequate facility maintenance, distribution property losses, cyber-security risks and dangers that exist in the gathering and transportation of gas in pipelines.

Increasing costs associated with our healthcare plans and other benefits may adversely affect our results of operations, financial position or liquidity.

The costs of providing healthcare benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to healthcare plans for our employees and former employees, will continue to rise. Significant regulatory developments have, and likely will continue to, require changes to our current employee benefit plans and in our administrative and accounting processes, as well as changes to the cost of our plans, and the increasing costs and funding requirements associated with our healthcare plans may adversely affect our results of operations, financial position or cash flows.

Our electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, there can be no assurance that the state public utility commissions will allow recovery.

An effective system of internal control may not be maintained, leading to material weaknesses in internal control over financial reporting.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to make an assessment of the design and effectiveness of internal controls. Our independent registered public accounting firm is required to attest to the effectiveness of these controls. During their assessment of these controls, management or our independent registered public accounting firm may identify areas of weakness in control design or effectiveness, which may lead to the conclusion that a material weakness in internal control exists. Any control deficiencies we identify in the future could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. If we are unable to assert that our internal controls over financial reporting are effective, market perception of our business, operating results and stock price could be adversely affected.

ENVIRONMENTAL RISKS

Developments in federal and state laws concerning GHG regulations and air emissions relating to climate may adversely impact operations, financial results and materially increase our generation and production costs, which could render some of our generating units uneconomical to operate and maintain.

To the extent climate change occurs, our businesses could be adversely impacted. We believe it is likely that any such resulting impacts would occur very gradually over a very long period of time and thus would be difficult to quantify. Warmer temperatures in our natural gas service territories, or cooler temperatures in our electric service territories could adversely affect financial results through lower natural gas volumes delivered, lower MWh sold and associated lower revenues.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming and Colorado. Developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants may result in more stringent emission limitations, which could have a material impact on our costs of operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the section "Environmental Matters".

Due to uncertainty as to the final outcome of federal climate regulation, legal challenges, state CPP developments or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, financial position or cash flows.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or reduction of load of coal-fired power generation facilities and potential increased load of our combined cycle natural gas-fired generation units. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

The costs to achieve or maintain compliance with existing or future governmental laws, regulations or requirements, and any failure to do so, could adversely affect our results of operations, financial position or liquidity.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

The business segments may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on the business segments' financial position, results of operations or cash flows, future environmental compliance costs could have a significant negative impact.

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization and the use of alternative energy sources for power generation as mandated by states could reduce coal consumption.

Future regulations may require further reductions in emissions of mercury, hazardous pollutants, SO_2, NO_x, volatile organic compounds, particulate matter and GHG, which are released into the air when coal is burned. These requirements could require the installation of costly emission control technology or the implementation of other measures.

Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. The EPA was directed to repeal, revise and replace the CPP rule. At this time, it is not known what effect this will have on coal as a domestic energy source, and could have a significant impact on our mining operations.

Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our results of operations, financial position or cash flows could be adversely impacted.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the "Legal Proceedings" sub-caption within Item 8, Note 19, "Commitments and Contingencies", of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Annual Report.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of December 31, 2018, we had 3,689 common shareholders of record and approximately 41,000 beneficial owners, representing all 50 states, the District of Columbia and 7 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 30, 2019 meeting, our Board of Directors declared a quarterly dividend of $0.505 per share, equivalent to an annual dividend of $2.02 per share. The 2019 equivalent rate of $2.02 per share would mark 2019 as the 49th consecutive annual dividend increase for the Company.

For additional discussion of our dividend policy and factors that may limit our ability to pay dividends, see "Liquidity and Capital Resources" under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-K.

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2018.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the twelve months ended December 31, 2018.

ITEM 6. SELECTED FINANCIAL DATA

(Minor differences may result due to rounding)

Years Ended December 31, (dollars in thousands, except per share amounts)	2018	2017	2016	2015	2014
Total Assets	$ 6,963,327	$ 6,658,902	$ 6,541,773	$ 4,626,643	$ 4,216,752
Property, Plant and Equipment					
Total property, plant and equipment	$ 6,000,015	$ 5,567,518	$ 5,315,296	$ 3,849,309	$ 3,606,931
Accumulated depreciation and depletion	(1,145,136)	(1,026,088)	(929,119)	(794,695)	(714,762)
Total property, plant and equipment, net	$ 4,854,879	$ 4,541,430	$ 4,386,177	$ 3,054,614	$ 2,892,169
Capital Expenditures					
Continuing Operations	$ 502,424	$ 337,689	$ 460,450	$ 289,896	$ 281,828
Discontinued Operations	2,402	23,222	6,669	168,925	109,439
Total Capital Expenditures	$ 504,826	$ 360,911	$ 467,119	$ 458,821	$ 391,267
Capitalization (excluding noncontrolling interests)					
Current maturities of long-term debt	$ 5,743	$ 5,743	$ 5,743	$ —	$ 275,000
Notes payable	185,620	211,300	96,600	76,800	75,000
Long-term debt, net of current maturities and deferred financing costs	2,950,835	3,109,400	3,211,189 (a)	1,853,682	1,255,953
Common stock equity (b)	2,181,588	1,708,974	1,614,639	1,465,867	1,353,884
Total capitalization	$ 5,323,786	$ 5,035,417	$ 4,928,171	$ 3,396,349	$ 2,959,837
Capitalization Ratios					
Short-term debt, including current maturities	4%	4%	2%	2%	12%
Long-term debt, net of current maturities	55%	62%	65% (a)	55%	42%
Common stock equity	41%	34%	33%	43%	46%
Total	100%	100%	100%	100%	100%
Total Operating Revenues	$ 1,754,268	$ 1,680,266	$ 1,538,916	$ 1,261,322	$ 1,338,456
Net Income Available for Common Stock (h)					
Electric Utilities	$ 78,940	$ 110,082	$ 85,827	$ 77,579	$ 57,270
Gas Utilities	160,283 (g)	65,795	59,624	39,306	44,151
Power Generation	20,777 (c)	46,479 (c)	25,930 (c)	32,650	28,516
Mining	12,899	14,386	10,053	11,870	10,452
Corporate and intersegment eliminations	(7,570)	(42,609) (d)	(44,302) (d)	(19,857) (d)	(7,927)
Income (loss) from continuing operations available for common stock	265,329	194,133	137,132	141,548	132,462
Income (loss) from discontinued operations, net of tax (b)	(6,887)	(17,099)	(64,162)	(173,659)	(1,573)
Net income (loss) available for common stock	$ 258,442	$ 177,034	$ 72,970	$ (32,111)	$ 130,889

SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2018	2017	2016	2015	2014
Dividends Paid on Common Stock	$ 106,591	$ 96,744	$ 87,570	$ 72,604	$ 69,636
Common Stock Data[e] (in thousands)					
Shares outstanding, average basic	54,420	53,221	51,922	45,288	44,394
Shares outstanding, average diluted	55,486	55,120	53,271	45,288	44,598
Shares outstanding, end of year	60,004	53,541	53,382	51,192	44,672
Earnings (Loss) Per Share of Common Stock (in dollars)					
Basic earnings (loss) per average share -					
Continuing operations	$ 5.14	$ 3.92	$ 2.83	$ 3.12	$ 2.98
Discontinued operations [b]	(0.13)	(0.32)	(1.23)	(3.83)	(0.04)
Non-controlling interest	(0.26)	(0.27)	(0.19)	—	—
Total	$ 4.75	$ 3.33	$ 1.41	$ (0.71)	$ 2.94
Diluted earnings (loss) per average share -					
Continuing operations	$ 5.04	$ 3.78	$ 2.75	$ 3.12	$ 2.97
Discontinued operations [b]	(0.12)	(0.31)	(1.20)	(3.83)	(0.04)
Non-controlling interest	(0.26)	(0.26)	(0.18)	—	—
Total	$ 4.66	$ 3.21	$ 1.37	$ (0.71)	$ 2.93
Dividends Declared per Share	$ 1.93	$ 1.81	$ 1.68	$ 1.62	$ 1.56
Book Value Per Share, End of Year	$ 36.36	$ 31.92	$ 30.25	$ 28.63	$ 30.31
Return on Average Equity [f]	13.6%	11.7%	8.9%	10.0%	10.0%

(a) The increase in 2016 includes the debt associated with the SourceGas acquisition (see Note 6 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K).

(b) On November 1, 2017, we made the decision to divest our Oil and Gas assets. 2017 includes an after-tax fair value impairment on held-for-sale assets of $13 million. 2016 includes non-cash after-tax impairment charges to crude oil and natural gas properties of $67 million. 2015 includes non-cash after-tax ceiling test impairment charges to crude oil and natural gas properties of $158 million and a non-cash after-tax equity investment impairment charge of $2.9 million (see Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K).

(c) On April 14, 2016, Black Hills Electric Generation sold a 49.9% interest in Black Hills Colorado IPP. Net income available for common stock for 2018, 2017 and 2016 was reduced by $14 million, $14 million and $9.6 million, respectively, attributable to this noncontrolling interest.

(d) 2017, 2016 and 2015 include incremental SourceGas Acquisition costs, after-tax of $2.8 million, $30 million and $6.7 million, respectively. 2016 and 2015 also include after-tax internal labor costs attributable to the SourceGas Acquisition of $9.1 million and $3.0 million that otherwise would have been charged to other segments.

(e) On November 1, 2018, we issued 6.3 million shares of common stock upon conversion of our Equity Units. In 2016, we issued 1.97 million shares at an average share price of $60.95 under our ATM equity offering program. In November 2015, we issued 6.3 million shares of common stock, par value $1.00 per share at a price of $40.25.

(f) Calculated based on Net income (loss) from continuing operations available for common stock.

(g) The increase in 2018 included a $73 million tax benefit resulting from legal entity restructuring. See Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

(h) Net income (loss) from continuing operations for the year ended December 31, 2018 included approximately $4.0 million of income tax expense associated with changes in the prior estimated impact of tax reform on regulatory liabilities and deferred income taxes. The (expense) benefit impact to our operating segments and Corporate and Other for the year ended December. 31, 2018 was: Electric Utilities ($4.2) million; Gas Utilities $0.5 million; Power Generation ($0.7) million; Mining ($0.5) million; and Corporate and Other $0.9 million, respectively. Net Income from continuing operations for the year ended December 31, 2017 includes a net tax benefit of $7.6 million from the revaluation of deferred tax balances due to a decrease in the statutory Federal income tax rate resulting from the TCJA. The (expense) benefit impact to our operating segments and Corporate and Other for the year ended December 31, 2017 was: Electric Utilities $23 million; Gas Utilities ($6.8) million; Power Generation $24 million; Mining $2.7 million; and Corporate and Other ($35) million, respectively.

For additional information on our business segments see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note 5 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEMS 7 & and 7A. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a customer-focused, growth-oriented electric and natural gas utility company with a mission of improving life with energy and a vision to be the energy partner of choice. The Company provides electricity and natural gas through its Electric Utilities and Gas Utilities to 1.27 million customers in 823 communities in eight states, including Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. The Company conducts its utility operations under the name Black Hills Energy predominantly in rural areas of the Rocky Mountains and Midwestern states. The Company's Electric Utilities are supported by our Power Generation and Mining segments. The Power Generation segment produces electric power from its three generating plants and sells the electric capacity and energy principally to our Electric Utilities under long-term contracts. Our Mining segment produces coal at our mine near Gillette, Wyoming, and sells the coal primarily to fuel the on-site, mine-mouth power generation facilities.

The Company has provided energy and served customers for 135 years, since the 1883 gold rush days in Deadwood, South Dakota. Throughout our history, the common thread that unites the past to the present is our commitment to serve our customers and communities. Our strategic focus has not changed in over a century - serving customers with affordable, reliable and safe energy. Our strategy today continues that emphasis on serving customers, but with a renewed focus on better engaging with the people and communities we serve. Customer expectations are rapidly changing with the advancement of technology and customers are demanding simpler, faster and more convenient solutions to their energy needs. We are ready to serve as we have done for the past 135 years.

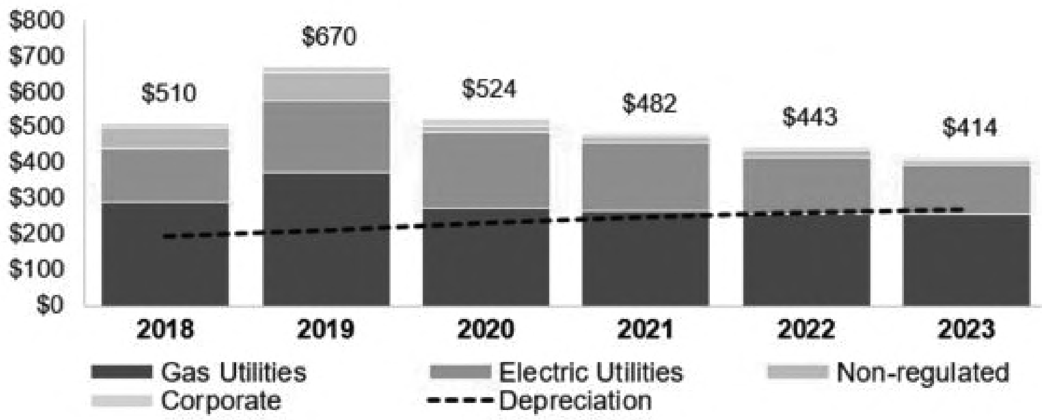
Our strategy consists of five primary areas that focus on improving the way we serve customers with safe, reliable and affordable energy while improving the lives of the customers and communities we serve. The strategy is to 1) modernize utility infrastructure 2) pursue operating efficiencies 3) transform the customer experience 4) add renewable generation to meet customer demand and 5) become the safest energy company in the utility industry. This strategic focus will present the company with significant investment opportunities over the next several years as we modernize our infrastructure systems and meet customer growth. It will also allow us to better understand our customer and community needs while providing more intuitive and cost-effective interactions.

Key Elements of our Business Strategy

Replace, modernize and operate utility infrastructure to meet our customer's energy needs by providing safe and reliable energy. Our utilities own and operate large electric and natural gas infrastructure systems that span nearly 1,600 miles, reaching from Cody, Wyoming to Blytheville, Arkansas. Our Gas Utilities own and operate 45,000 miles of natural gas transmission and distribution pipelines and our Electric Utilities own and operate 939 MW of generation capacity and 8,800 miles of transmission and distribution lines. A key strategic focus is to modernize this utility infrastructure to meet customers and communities' varied energy needs and to ensure the continued delivery of safe and reliable energy. In addition, we need to invest in the accessibility, capacity and integrity of our systems to meet customer growth. An overriding strategic focus in all that we do is to ensure the safe delivery of energy to our customers and communities, particularly in light of recent industry pipeline accidents.

A key component of our modernization effort is the development of programs by our Electric and Gas utilities to systematically and proactively replace aging infrastructure on a system-wide basis. To support its safety and reliability focus, our Gas Utilities have developed a programmatic approach to system-wide pipeline system replacement, particularly in high consequence areas. Under the programmatic approach, obsolete, at-risk and vintage materials will be replaced in a proactive and systematic time frame. To meet our electric customers' continued expectations of high levels of reliability, our Electric Utilities are developing a distribution integrity program to ensure the timely repair and replacement of an aging infrastructure system.

We estimate our five-year capital investment to be approximately $2.5 billion, with most of that investment targeted toward replacing existing utility infrastructure and to meet customer growth. Our actual 2018 and estimated capital expenditures for next five years from 2019 through 2023 are as follows (in millions):



	Actual	Planned	Planned	Planned	Planned	Planned
Capital Expenditures By Segment	2018	2019	2020	2021	2022	2023
(in millions)						
Electric Utilities	$ 153	$ 200	$ 213	$ 191	$ 160	$ 137
Gas Utilities	288	374	273	264	257	259
Power Generation [(a)]	38	72	9	8	10	4
Mining	19	8	7	11	10	7
Corporate and Other	12	16	22	8	6	7
Total	$ 510	$ 670	$ 524	$ 482	$ 443	$ 414

(a) 2018 includes the $7.6 million Busch Ranch 1 Wind Farm contract intangible asset. See Note 4, “Jointly Owned Facilities”, of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further information.

Maintain a safe and reliable gas distribution system. We rigorously comply with all applicable federal, state and local regulations and strive to consistently meet industry best practice standards. Preventing natural gas losses from our gas delivery systems is of the utmost importance to ensure public and employee safety and to protect the environment. We construct, maintain and update our gas delivery systems with state of the art materials and products and continuously monitor their integrity. System leaks are repaired as soon as possible while focusing on the safety of the public and our employees. We have removed all cast and wrought iron from our natural gas transmission and distribution systems and continue to replace aging infrastructure through programs that prioritize safety and reliability for our customers. Many of our Gas Utilities are authorized to use system safety, integrity and replacement cost recovery mechanisms that provide for customer rate adjustments which reflect the cost incurred in repairing and replacing the gas delivery systems.

Efficiently plan, construct and operate rate base power generation facilities to serve our Electric Utilities. We believe that we best serve customers and communities with a vertically integrated business model for our Electric Utilities. This business model remains a core strength and strategy today as we invest in and operate efficient power generation resources to cost-effectively supply electricity to our customers. We strive to provide power at reasonable rates to our customers and earn competitive returns for our investors.

Our power production strategy focuses on low-cost construction and efficient operation of our generating facilities. Our low-power production costs result from a variety of factors including low fuel costs, efficiency in converting fuel into energy, low per unit operating and maintenance costs and high levels of power plant availability. For our coal-fired power plants, we leverage the mine-mouth location advantage to eliminate coal transportation costs that often represent the largest component of the delivered cost of coal for many other utilities. Additionally, we operate our plants with high levels of availability as compared to industry benchmarks.

We continue to believe that ownership of power generation facilities by our Electric Utilities best serves customers. Rate-based generation assets offer several advantages for customers and shareholders, including:

- When generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run; especially when compared to power otherwise purchased from the open market through wholesale contracts that are periodically re-priced to reflect current and varying market conditions;

- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;

- The lower-risk profile of rate-based generation assets contributes to stronger credit ratings which, in turn, can benefit both customers and investors by lowering the cost of capital; and

- Investors are provided a long-term, reasonable, stable return on their investment.

Proactively integrate alternative and renewable energy into our utility energy supply while mitigating customer rate impacts. Some of our customers, particularly our larger customers, are demanding more renewable and cleaner sources of energy to meet their sustainability goals. In addition, there is more interest from voters, regulators and legislators to increase the use of renewable and other alternative energy sources. To support this interest, we have filed for approval of new, voluntary renewable energy tariffs to serve commercial, industrial and government customer requests for renewable energy resources in South Dakota and Wyoming. These efforts may provide potential investment opportunities to incorporate more wind and solar generation into our generation fleet to meet customers' requests or legislative requirements.

To date, many states have enacted, and others are considering, mandatory renewable energy standards, requiring utilities to meet certain thresholds of renewable energy generation. Some states have either enacted or are considering legislation setting GHG emissions reduction targets. Federal legislation for both renewable energy standards and GHG emission reductions has been considered and may be implemented in the future. Mandates for the use of renewable energy or the reduction of GHG emissions will likely provide investment opportunities for our Electric Utilities, Gas Utilities and Power Generation segment. These mandates will also likely increase prices for electricity and/or natural gas for our utility customers. As a regulated utility we are responsible for providing safe, reliable and affordable sources of energy to our customers. Accordingly, we employ a customer-focused strategy for complying with renewable energy standards and GHG emission regulations that balance our customers' rate concerns with environmental considerations and administrative and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers.

Build and maintain strong relationships with wholesale power customers of our utilities and our power generation business. We strive to build strong relationships with other utilities, municipalities and wholesale customers. We believe we will continue to be an important provider of electricity to wholesale utility customers, who will continue to need products such as capacity and energy to reliably serve their customers. By providing these products under long-term contracts, we help our customers meet their energy needs. We also earn more stable revenues and greater returns for shareholders over the long-term than we would by selling energy into more volatile energy spot markets. In addition, relationships that we have established with wholesale power customers have developed into other opportunities. MEAN, MDU and the City of Gillette, Wyoming were wholesale power customers that are now joint owners in two of our power plants, Wygen I and Wygen III, reducing risk and providing steady revenues.

Vertically integrate businesses that are supportive of our Electric and Gas utility businesses. While our primary focus is on growing our core utilities, we selectively invest in vertically integrated businesses that provide cost effective and efficient fuel and energy to our utilities. We currently own and operate a coal mine and power generation assets that are vertically integrated into and supportive of our Electric Utilities. These operations are located at our utility-generating complexes and are physically integrated into our Electric Utility operations.

Our surface coal mine is located immediately adjacent to our Gillette energy complex in northeastern Wyoming, where all five of our coal-fired power plants are located. We operate and own majority interests in four of the five power plants. We own 20% of the fifth power plant which is operated by the majority owner. The coal mine provides low-sulfur coal directly to these power plants via a conveyor belt system, minimizing coal transportation costs. On average, the coal can be delivered to the adjacent power plants at less than $1.00 per MMBtu, providing very cost competitive fuel to our power plants when compared to other coal-fired and gas-fired power plants. Nearly all of the mine's coal production is sold to the five on-site, mine-mouth generation facilities under long-term supply contracts. Approximately one-half of our coal is sold under cost-plus contracts with affiliates. A small portion of the mine's coal production is sold to off-site industrial customers and delivered by truck.

Our Power Generation segment has an experienced staff with significant expertise in planning, building and operating power plants. The power generation team has constructed 19 coal-fired, gas-fired and renewable generation projects since 1995 with aggregate project costs in excess of $2 billion. This group also provides shared services to our Electric Utilities' generation facilities, resulting in efficient management of all of the company's generation assets. In certain states, our Electric Utilities are required to competitively bid for generation resources needed to serve customers. Generally, our Power Generation segment submits bids in response to those competitive solicitations. Our Power Generation segment can often realize competitive advantages provided by prior construction expertise, fuel supply advantages and by co-locating new plants at existing sites, reducing infrastructure and operating costs. The Power Generation segment currently owns three power plants, which are contracted with our affiliate Electric Utilities under long-term power purchase agreements. In addition, Power Generation is currently building a 60 MW wind farm for Colorado Electric after winning a solicitation for renewable energy.

Expand utility operations through selective acquisitions of electric and gas utilities. The electric and natural gas utility industries have consolidated significantly over the past two decades and continue to consolidate. We have successfully acquired and integrated numerous utility systems since 2005, including two large, transformational acquisitions - the Aquila utility properties in 2008 and SourceGas in 2016. Through these acquisitions, we developed a scalable platform that simplifies the rapid integration of acquired utilities, providing significant benefits to both customers and shareholders. The company targets small to large utilities, including municipal and private utility systems, located primarily in geographies that are near to or contiguous with our existing utility service territories and provide long-term value for both customers and shareholders. In the near-term, we do not expect to pursue large utility acquisitions, particularly given the high valuation multiples realized in recent utility transactions. We will continue to pursue the purchase of small utility systems within or near our geographic footprint, which can be quickly and efficiently integrated into our existing utilities. As pipeline regulations continue to increase, we believe there will be more opportunities to purchase these smaller and more rural utility systems.

Grow our dividend. We are extremely proud of our track record for annual dividend increases for shareholders. In January 2019, we declared a dividend of $0.505 per share, equivalent to an annual dividend rate of $2.02 per share. This annual equivalent rate represents an increase of 5% over the total 2018 dividend of $1.93 per share and the 49th consecutive annual dividend increase. We intend to continue our record of annual dividend increases with a targeted dividend payout ratio of 50% to 60%. This target payout ratio provides the flexibility for greater increases to our dividend during periods of relatively slow earnings growth.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. We require access to the capital markets to fund our planned capital investments or acquire strategic assets that support prudent and earnings accretive business growth. We have demonstrated our ability to cost-effectively access the debt and equity markets, while maintaining our investment-grade issuer credit rating.

Prospective Information

We expect to generate long-term growth through the expansion of integrated utilities and supporting operations. Sustained growth requires continued capital deployment. Our integrated energy portfolio, focused primarily on regulated utilities provides growth opportunities, yet avoids concentrating business risk. We expect much of our growth in the next few years will come from capital deployment opportunities at our utilities and continued focus on improving efficiencies and reducing costs. Although dependent on market conditions, we are confident in our ability to obtain additional financing, as necessary, to continue our growth plans. We remain focused on prudently managing our operations and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan. Prospective information for our operating segments should be read in conjunction with our business strategy discussed above, and our 2018 company highlights discussed below.

Results of Operations

Executive Summary and Overview

	For the Years Ended December 31,				
	2018	Variance	2017	Variance	2016
	(in thousands)				
Revenue					
Revenue	$ 1,893,743	$ 83,296	$ 1,810,447	$ 143,412	$ 1,667,035
Intercompany eliminations	(139,475)	(9,294)	(130,181)	(2,062)	(128,119)
	$ 1,754,268	$ 74,002	$ 1,680,266	$ 141,350	$ 1,538,916
Income from continuing operations available for common stock [(a)]					
Electric Utilities [(a)]	$ 78,940	$ (31,142)	$ 110,082	$ 24,255	$ 85,827
Gas Utilities [(a) (b) (c)]	160,283	94,488	65,795	6,171	59,624
Power Generation [(a) (d)]	20,777	(25,702)	46,479	20,549	25,930
Mining [(a)]	12,899	(1,487)	14,386	4,333	10,053
	272,899	36,157	236,742	55,308	181,434
Corporate and Other [(a) (e) (f)]	(7,570)	35,039	(42,609)	1,693	(44,302)
Income from continuing operations	265,329	71,196	194,133	57,001	137,132
(Loss) from discontinued operations, net of tax [(g)]	(6,887)	10,212	(17,099)	47,063	(64,162)
Net income (loss) available for common stock	$ 258,442	$ 81,408	$ 177,034	$ 104,064	$ 72,970

(a) Income (loss) from continuing operations for 2018 included approximately $4.0 million of income tax expense associated with changes in the prior estimated impact of tax reform on regulatory liabilities and deferred income taxes. Income from continuing operations for 2017 includes a net tax benefit of $7.6 million from the revaluation of deferred tax balances due to a decrease in the statutory Federal income tax rate resulting from the TCJA. See the table below for the impact to each segment for both years.

(b) Income (loss) from continuing operations for 2018 included a $73 million tax benefit resulting from legal entity restructuring. See Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

(c) Income from continuing operations for 2017 includes a $4.1 million tax benefit from a true-up to the filed 2016 SourceGas tax returns relating to the SourceGas Acquisition.

(d) On April 14, 2016, BHEG sold a 49.9% interest in Black Hills Colorado IPP. Net income (loss) from continuing operations available for common stock for 2018, 2017 and 2016 was reduced by $14 million, $14 million and $9.6 million, respectively, attributable to this noncontrolling interest.

(e) Income from continuing operations for 2017 and 2016 include incremental SourceGas Acquisition costs, after-tax of $2.8 million and $30 million, respectively and after-tax internal labor costs attributable to the SourceGas Acquisition of $0.5 million and $9.1 million, respectively, that otherwise would have been charged to other business segments.

(f) Income from continuing operations for 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

(g) Loss from discontinued operations in 2017 and 2016 included non-cash after-tax impairments of crude oil and natural gas properties of $13 million and $67 million, respectively. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

The following business group and segment information does not include intercompany eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated. Per share information references diluted shares unless otherwise noted.

2018 Compared to 2017

Income from continuing operations available for common stock was $265 million, or $4.78 per diluted share in 2018 compared to $194 million, or $3.52 per diluted share in 2017. The variance to the prior year was primarily due to:

- Gas Utilities' earnings, excluding tax reform impacts, increased approximately $87 million primarily due to the recognition of a $73 million tax benefit resulting from legal entity restructuring (See Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information); earnings also benefited from colder winter weather and increased sales of natural gas, offset by an increase in operating expenses;
- Earnings at our Mining segment, excluding tax reform impacts, increased $1.7 million primarily due to increased price per ton sold and lower operating expenses;
- Electric Utilities' earnings, excluding tax reform impacts, decreased by $3.5 million due primarily to a settlement agreement with the WPSC which decreased gross margins by $2.6 million; other variances to the prior year were due to higher operating expenses driven by facility costs, employee costs, contractor and consulting expenses, and vegetation management expenses, partially offset by higher rider revenues from recent transmission investments, higher power marketing and wholesale margins, and favorable weather;
- Earnings at our Power Generation segment, excluding tax reform impacts, decreased $1.2 million primarily due to higher operating expenses;
- Corporate and Other expenses, excluding tax reform impacts, increased by approximately $1.3 million primarily due to higher intercompany allocations of tax expense, partially offset by a decrease in acquisition and transition costs occurring in the prior year; and
- In 2018, we recorded $4.0 million of income tax (expense) associated with changes in the prior estimated impact of tax reform on regulatory liabilities and deferred income taxes compared to a net tax benefit of approximately $7.6 million as a result of the revaluation of deferred tax balances due to the decrease in the statutory Federal income tax rate as a result of the TCJA. The impacts to our operating segments and Corporate and Other for 2018 and 2017 were (in millions):

Segment	2018	2017
Electric Utilities	$ (4.2)	$ 23.4
Gas Utilities	0.5	(6.8)
Power Generation	(0.7)	23.8
Mining	(0.5)	2.7
Corporate and Other	0.9	(35.5)
Total tax (expense) benefit	$ (4.0)	$ 7.6

Net income (loss) available for common stock was $258 million, or $4.66 per diluted share in 2018, compared to $177 million, or $3.21 per share in 2017. (Loss) from discontinued operations was $(6.9) million or $(0.12) per diluted share in 2018 compared to $(17) million or $(0.31) per diluted share in 2017. Discontinued operations in 2017 included an after-tax fair value impairment of assets of approximately $13 million.

2018 Overview of Business Segments and Corporate Activity

Electric Utilities

- On December 17, 2018, South Dakota Electric and Wyoming Electric filed for approval with the SDPUC and WPSC, new voluntary renewable energy tariffs to serve customer requests for renewable energy resources. In addition, South Dakota Electric and Wyoming Electric filed a joint application with the WPSC for a CPCN to construct a $57 million, 40 MW wind generation project near Cheyenne, Wyoming.

- On December 6, 2018, Wyoming Electric set a new all-time winter peak load of 238 MW, exceeding the previous winter peak of 230 MW set on December 7, 2016.

- On November 30, 2018, Wyoming Electric submitted its 2018 integrated resource plan to the WPSC, which included the recommendation that Wyoming Electric acquire Wygen I. Review of Wyoming Electric's integrated resource plan is subject to an open public process governed by the WPSC. The purchase of Wygen I would require approval of a CPCN by the WPSC and approval by FERC. The review process is expected to be completed by year-end 2019.

- On October 31, 2018, Wyoming Electric received approval from the WPSC for a comprehensive, multi-year settlement regarding its PCA Application filed earlier in 2018. Wyoming Electric will provide a total of $7.0 million in customer credits through the PCA mechanism in 2018, 2019 and 2020 to resolve several years of disputed issues related to PCA dockets before the commission. The settlement also stipulates that the adjustment for the variable cost segment of the Wygen I Power Purchase Agreement with Wyoming Electric (an affiliate company) will escalate by 3% annually through 2022.

- On October 3, 2018, Colorado Electric set a new all-time winter peak load of 313 MW, exceeding the previous winter peak of 310 MW set in February 2011.

- Cooling degree days for the year ended December 31, 2018 were 29% higher than the 30-year average (normal) compared to 14% higher than normal in 2017.

  Heating degree days for the year ended December 31, 2018 were 3% higher than normal compared to 11% lower than normal in 2017.

- Wyoming Electric and Colorado Electric set new summer peak loads:

  - On July 10, 2018, Wyoming Electric set a new all-time peak load of 254 MW, exceeding the previous summer peak of 249 MW set in July 2017.

  - On June 27, 2018, Colorado Electric set a new all-time peak load of 413 MW, exceeding the previous summer peak of 412 MW set in July 2016.

- On November 20, 2018, South Dakota Electric placed in service a 33-mile segment of a $70 million, 175-mile, 230-kV transmission line from Rapid City, South Dakota, to Stegall, Nebraska. The first 48-mile segment was placed in service on July 25, 2018. The remaining 94-mile segment is expected to be in service by the end of 2019.

- On April 25, 2018, Colorado Electric received approval from the CPUC to contract with Black Hills Electric Generation for the 60 MW Busch Ranch II wind project. The project is currently under construction and is expected to be in service by the end of 2019. This renewable energy will enable Colorado Electric to comply with Colorado's Renewable Energy Standard.

Gas Utilities

- Rate Review updates:

  - On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting approval to consolidate the base rate areas, tariffs, terms and conditions and adjustment clauses of its two legacy utilities. The rate review also requests $2.5 million in new revenue to recover costs and investments, in safety, reliability and system integrity. See Note 13 for additional details.

  - On October 5, 2018, Arkansas Gas received approval from the APSC for a general rate increase. The new rates will generate approximately $12 million of new revenue. The APSC’s approval also allows Arkansas Gas to include $11 million of revenue that is currently being collected through certain rider mechanisms in the new base rates. The new revenue increase is based on a return on equity of 9.61% and a capital structure of 49.1% equity and 50.9% debt. New rates, inclusive of customer benefits related to the TCJA, were effective October 15, 2018.

  - On July 16, 2018, the WPSC approved our Wyoming Gas (Northwest Wyoming) settlement and stipulation with the OCA. The settlement provides for $1.0 million of new revenue, a return on equity of 9.6%, and a capital structure of 54.0% equity and 46.0% debt. New rates, inclusive of customer benefits related to the TCJA, were effective September 1, 2018.

  - In Colorado, RMNG implemented new rates after approval of a settlement of a rate review filed in October 2017. The settlement included $1.1 million in annual revenue increases and an extension of SSIR to recover costs from 2018 through 2021. The annual increase is based on a return on equity of 9.9% and a capital structure of 46.63% equity and 53.37% debt. New rates are inclusive of customer benefits related to the TCJA.

- On November 20, 2018, Wyoming Gas received approval from the WPSC for a CPCN to construct a new $54 million, 35-mile natural gas pipeline to enhance supply reliability and delivery capacity for approximately 57,000 customers in central Wyoming. The pipeline, known as the Natural Bridge Pipeline, is planned to be in service in late 2019.

- Certain legal entity restructuring transactions occurred on March 31, 2018 and December 31, 2018 as part of the Company's ongoing efforts to continue to integrate the legal entities that the Company has acquired in recent years. As a result of these transactions, additional deferred income tax assets of $73 million, related to goodwill that is amortizable for tax purposes, were recorded with a corresponding deferred tax benefit recorded on the Consolidated Statements of Income.

- Heating degree days at the Gas Utilities for the year ended December 31, 2018 were 2% higher than the 30-year average (normal) compared to 10% lower than normal in 2017.

<u>Power Generation</u>

- On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest in the 29 MW Busch Ranch I Wind Farm, previously owned by AltaGas, for $16 million.

- On April 25, 2018, Black Hills Electric Generation was selected to provide 60 MW of renewable energy to Colorado Electric from the Busch Ranch II wind project, which is expected to be in service by the end of 2019.

<u>Corporate and Other</u>

- On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued in November 2015. Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of $299 million in exchange for approximately 6.372 million shares of common stock. Proceeds were used to pay off $250 million of debt maturing in January 2019 and other short-term debt.

- On October 11, 2018, Fitch affirmed Black Hills' credit rating at BBB+ and maintained a Stable outlook.

- On August 17, 2018, we completed a public debt offering of $400 million principal amount of 4.350% senior unsecured notes. The proceeds were used to repay the $299 million principal amount of our RSNs due 2028 and pay down short-term debt.

- On August 9, 2018, S&P upgraded Black Hills' credit rating to BBB+ with a Stable outlook and South Dakota Electric's credit rating to A.

- On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former Revolving Credit Facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and the banks increasing or providing new commitments, to increase total commitments of the facility up to $1.0 billion.

- On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at December 31, 2018, matures on July 30, 2020.

- On July 19, 2018, Fitch affirmed South Dakota Electric's credit rating at A.

<u>Discontinued Operations</u>

- On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. As of December 31, 2018, we have completed the divestiture of our oil and gas assets. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

2017 Compared to 2016

Income from continuing operations available for common stock was $194 million, or $3.52 per diluted share in 2017 compared to $137 million, or $2.57 per diluted share in 2016. The variance to the prior year was primarily due to:

- Corporate and Other, excluding tax reform impacts, decreased by approximately $37 million compared to the same period in the prior year driven primarily by a $27 million reduction of after-tax external acquisition and transition costs, a reduction of approximately $8.6 million of internal labor attributed to the SourceGas Acquisition and lower reallocated discontinued operation expenses of approximately $2.9 million, partially offset by a $4.4 million tax benefit in 2016;
- Gas Utilities' earnings, excluding tax reform impacts, increased approximately $13 million, with a full year of earnings from our acquired SourceGas utilities compared to approximately 10.5 months in 2016; and a $4.1 million tax benefit recognized in 2017;
- We recorded a net tax benefit of approximately $8 million as a result of the revaluation of deferred tax balances due to the decrease in the statutory Federal income tax rate as a result of the TCJA. This benefit's impact to our operating segments and Corporate and Other was:
    - Electric Utilities - $23 million tax benefit
    - Gas Utilities - $6.8 million tax expense
    - Power Generation - $24 million tax benefit
    - Mining - $2.7 million tax benefit
    - Corporate and Other - $35 million tax expense consisting of $28 million of tax expense from the revaluation of Corporate deferred tax balances and $7 million of tax expense from the revaluation of deferred taxes that were originally recorded to AOCI.
- Electric Utilities' earnings, excluding tax reform impacts, were comparable to the prior year reflecting an increase from returns on prior year generation investments, offset by higher employee costs and higher generation maintenance expenses;
- Earnings at our Power Generation segment, excluding tax reform impacts, decreased $3.5 million primarily due to an increase in net income attributable to noncontrolling interests, reflecting a full year in 2017 compared to approximately 8.5 months in 2016; and
- Earnings at our Mining segment, excluding tax reform impacts, increased approximately $1.6 million due to an increase in tons sold as a result of an extended outage in the prior year.

Net income (loss) available for common stock was $177 million, or $3.21 per diluted share in 2017, compared to $73 million, or $1.37 per share in 2016. (Loss) from discontinued operations was $(17) million or $(0.31) per diluted share in 2017 compared to $(64) million or $(1.20) per diluted share in 2016. Discontinued operations in 2017 included an after-tax fair value impairment of assets of approximately $13 million compared to 2016 which included non-cash after-tax oil and gas property impairment charges of $67 million. Also included in 2016 discontinued operations was a $5.8 million tax benefit recognized from additional percentage depletion deductions that were claimed with respect to our oil and gas properties involving prior years.

2017 Overview of Business Segments and Corporate Activity

Electric Utilities

- In our Electric Utilities service territories, winter weather was mostly comparable to the prior year and the summer was milder in 2017 compared to the prior year. Heating degree days in 2017 were 3% lower than normal compared to 11% lower than normal in 2016. Cooling degree days for the full year of 2017 were 29% higher than normal compared to 14% higher than normal in 2016.

- On January 17, 2017, Colorado Electric received approval from the CPUC on a settlement agreement for its electric resource plan which provides for the addition of 60 MW of renewable energy to be in service by 2019. The resource plan was filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. In the second quarter of 2017, Colorado Electric issued a request for proposals to acquire renewable energy resources to comply with the Colorado Renewable Energy Standard and presented the results to the CPUC on February 9, 2018. See the Electric Utilities 2018 highlights above for the outcome of this proposal.

- Construction was completed on the 144 mile transmission line connecting the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service on May 30, 2017.

- On July 19, 2017, Wyoming Electric set a new summer load peak of 249 MW, exceeding the previous summer peak of 236 MW set in July 2016.

Gas Utilities

- Our service territories reported comparable year-over-year winter weather as measured by heating degree days compared to the 30-year average. Combined heating degree days for the full year in 2017 were 10% less than normal compared to 11% less than normal in the same period in 2016.

  The Gas Utilities also experienced cooler summer temperatures and higher precipitation levels during the third quarter of 2017 compared to the same period in 2016, which reduced the irrigation load delivered to agricultural customers, primarily in our Nebraska service territory.

- During the fourth quarter of 2017, Arkansas Gas, Wyoming Gas and RMNG all filed rate review applications with their respective state commissions. See the Gas Utilities 2018 highlights above for the outcomes of these rate reviews.

Corporate and Other

- On August 4, 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior year program other than the aggregate value increased from $200 million to $300 million. We did not issue any common shares during the twelve months ended December 31, 2017.

- 2017 credit rating updates: On December 12, 2017, Moody's affirmed Black Hills' credit rating at Baa2 with a Stable outlook. On October 4, 2017, Fitch affirmed Black Hills' credit rating at BBB+ rating and maintained a Stable outlook, and on July 21, 2017, S&P affirmed Black Hills' credit rating at BBB rating and maintained a Stable outlook.

Discontinued Operations

- On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

Operating Results

A discussion of operating results from our business segments follows.

All amounts are presented on a pre-tax basis unless otherwise indicated.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors' understanding of our operating performance.

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

Our gross margin measure may not be comparable to other companies' gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in thousands):

	2018	Variance	2017	Variance	2016
Revenue [a]	$ 711,451	$ 6,801	$ 704,650	$ 27,369	$ 677,281
Total fuel and purchased power	277,093	8,688	268,405	7,056	261,349
Gross margin [b] [c] [d]	434,358	(1,887)	436,245	20,313	415,932
Operations and maintenance	186,175	13,868	172,307	14,173	158,134
Depreciation and amortization	98,639	5,324	93,315	8,670	84,645
Total operating expenses	284,814	19,192	265,622	22,843	242,779
Operating income	149,544	(21,079)	170,623	(2,530)	173,153
Interest expense, net	(52,667)	(393)	(52,274)	(1,983)	(50,291)
Other income (expense), net	(1,235)	(2,965)	1,730	(1,463)	3,193
Income tax expense [a]	(16,702)	(6,705)	(9,997)	30,231	(40,228)
Net income (loss) available for common stock	$ 78,940	$ (31,142)	$ 110,082	$ 24,255	$ 85,827

(a) We estimated and recorded a reserve to revenue of approximately $22.3 million during year ended December 31, 2018 to reflect the lower federal income tax rate from the TCJA on our existing rate tariffs. This reduction to revenues is offset by lower tax expense and has no impact on overall results.
(b) Non-GAAP measure.
(c) The year ended December 31, 2018 includes Horizon Point shared facility revenues of approximately $11 million, which are allocated to all of our operating segments as facility expenses. This shared facility agreement has no impact on BHC's consolidated operating results.
(d) Gross margin was impacted for the year ended December 31, 2018 by ($4.3) million as a result of the Wyoming Electric PCA settlement.

	2018	2017	2016
Regulated power plant fleet availability:			
Coal-fired plants [(a)] [(b)]	93.9%	88.9%	90.2%
Natural gas fired plants and Other plants	96.4%	96.1%	95.1%
Wind [(c)]	96.9%	93.3%	79.3%
Total availability	95.6%	93.6%	93.5%
Wind capacity factor	39.2%	36.7%	36.6%

(a) 2017 reflects planned outages at Neil Simpson II, Wyodak, and Wygen II.
(b) 2016 reflects a planned outage at Wygen III, an extended planned outage at Wyodak and an unplanned outage at Neil Simpson II.
(c) 2017 and 2016 were lower due to the addition of Peak View Wind Project with ownership transfer in November, 2016.

2018 Compared to 2017

Gross margin [(a)] decreased over the prior year as a result of:

		(in millions)
TCJA revenue reserve	$	(22.3)
Wyoming Electric PCA Stipulation		(2.6)
Other		(0.6)
Horizon Point shared facility revenue [(b)]		9.8
Rider recovery		5.1
Weather		3.6
Power Marketing, ancillary wheeling and Tech Services		3.5
Residential customer growth		1.6
Total increase (decrease) in Gross margin [(a)]	$	(1.9)

(a) Non-GAAP measure
(b) Horizon Point shared facility revenue is offset by facility expenses at our operating segments and has no impact on consolidated results.

Operations and maintenance increased primarily due to higher facility costs of $4.5 million and higher employee costs of $3.6 million driven primarily by labor and benefits. Vegetation management expenses increased over the prior year by $2.9 million, contractor and consulting expenses increased by $1.2 million and property taxes increased by $1.0 million due to a higher asset base.

Depreciation and amortization increased primarily due to higher asset base driven by the prior year additions of Horizon Point and the Teckla-Lange transmission line as well as the current year completion of the first segment of the Rapid City-Stegall transmission line.

Interest expense, net was comparable to the same period in the prior year.

Other (expense) income, net decreased due to the presentation change of non-service pension costs to Other income (expense) in the current year, previously reported in Operations and maintenance, and higher prior year AFUDC associated with higher prior year capital spend.

Income tax benefit (expense): The effective tax rate increased in 2018 due to a prior year $23 million benefit resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017. In addition, current year expense increased due to $4.2 million of tax expense associated with changes in the prior estimated impact of tax reform on regulatory liabilities and deferred income taxes. This was partially offset by the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

2017 Compared to 2016

Gross margin [(a)] increased over the prior year as a result of:

	(in millions)	
Peak View Wind Project return on investment	$	7.8
Rider recovery		7.4
Other [(b)]		3.0
Commercial and industrial demand		2.1
Total increase in Gross margin [(a)]	$	20.3

(a) Non-GAAP measure
(b) Includes approximately 1.5 months of Horizon Point shared facility revenue.

Operations and maintenance increased primarily due to $4.8 million of higher employee costs as a result of prior year integration activities and transition expenses charged to Corporate and Other, $2.6 million of higher generation outage expenses, $1.9 million of higher property taxes with an increased asset base, and $1.7 million of higher operating expenses from the Peak View Wind Project and the 40 MW gas turbine at the Pueblo Airport Generating Station. An additional $1.3 million of indirect corporate costs are included at the Electric Utilities; these costs were previously charged to our Oil and Gas segment, now reported as discontinued operations.

Depreciation and amortization increased primarily due to a higher asset base driven partially by the addition of the Peak View Wind Project and the 40 MW gas turbine at the Pueblo Airport Generating Station.

Interest expense, net increased primarily due to higher intercompany debt resulting from additional investments as compared to the prior year.

Other (expense) income, net decreased due to reduced AFUDC with lower capital spend.

Income tax benefit (expense): The effective tax rate was lower in 2017 primarily due to a $23 million benefit resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017. This benefit was primarily related to the revaluation of net operating losses and other tax basis items not included in the ratemaking construct. Production tax credits associated with the Peak View Wind Project increased by $4.0 million reflecting a full year of production tax credits compared to two months in 2016. The prior year included a $1.3 million benefit related to the flow-through treatment of a treasury grant related to the Busch Ranch I Wind Project.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in thousands):

	2018	Variance	2017	Variance	2016
Revenue:					
Natural gas - regulated [(a)]	$ 942,924	$ 77,093	$ 865,831	$ 96,749	$ 769,082
Other - non-regulated	82,383	584	81,799	12,538	69,261
Total revenue	1,025,307	77,677	947,630	109,287	838,343
Cost of natural gas sold:					
Natural gas - regulated	442,530	61,271	381,259	65,641	315,618
Other - non-regulated	19,623	(8,721)	28,344	(8,203)	36,547
Total cost of natural gas sold	462,153	52,550	409,603	57,438	352,165
Gross margin [(b)]:					
Natural gas - regulated	500,394	15,822	484,572	31,108	453,464
Other - non-regulated	62,760	9,305	53,455	20,741	32,714
Total gross margin [(b)]	563,154	25,127	538,027	51,849	486,178
Operations and maintenance	291,481	22,291	269,190	23,364	245,826
Depreciation and amortization	86,434	2,702	83,732	5,397	78,335
Total operating expenses	377,915	24,993	352,922	28,761	324,161
Operating income	185,239	134	185,105	23,088	162,017
Interest expense, net	(80,180)	(1,605)	(78,575)	(3,562)	(75,013)
Other income (expense), net	(431)	398	(829)	(1,013)	184
Income tax expense [(a)]	55,655	95,454	(39,799)	(12,337)	(27,462)
Net income	160,283	94,381	65,902	6,176	59,726
Net income attributable to noncontrolling interest	—	107	(107)	(5)	(102)
Net income available for common stock	$ 160,283	$ 94,488	$ 65,795	$ 6,171	$ 59,624

(a) We estimated and recorded a reserve to revenue of approximately $20.5 million during the year ended December 31, 2018 to reflect the lower federal income tax rate from the TCJA on our existing rate tariffs. This reduction to revenues is offset by lower tax expense and has no impact on overall results.

(b) Non-GAAP measure.

2018 Compared to 2017

Gross margin [a] increased over the prior year as a result of:

	(in millions)
Weather [b]	$ 13.8
New rates	10.7
Customer growth - distribution	5.2
Mark-to-market gains on non-utility natural gas commodity contracts	4.0
Transport and transmission	3.6
Natural gas volumes sold	3.2
Non-utility - Choice Gas, Tech Services and appliance repair	2.7
Other	2.4
TCJA revenue reserve	(20.5)
Total increase (decrease) in Gross margin [a]	$ 25.1

(a) Non-GAAP measure
(b) Heating degree days at the Gas Utilities for the year ended December 31, 2018 were 2% higher than the 30-year average (normal) compared to 10% lower than normal in 2017.

Operations and maintenance increased primarily due to higher employee costs of $11.8 million driven by labor, benefits and additional headcount. Outside services, consulting, and contractor expenses increased by $4.0 million due primarily to expenses related to jurisdictional simplification. In addition, facility costs increased by $4.7 million and bad debt expense increased by $2.1 million driven by the current year increase in revenues.

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

Interest expense, net increased due to higher corporate allocations from financing activities.

Other (expense) income, net was comparable to the same period in the prior year.

Income tax: The effective tax rate decrease was due to legal restructuring to enable jurisdictional simplification that resulted in the recognition of a deferred tax benefit of approximately $73 million associated with amortizable goodwill for tax purposes. The current year rate also reflects the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018. In the prior year there was additional tax expense of $6.8 million as a result of the TCJA enacted on December 22, 2017, partially offset by $4.1 million tax benefit recognized in the prior year from a true-up to the filed 2016 SourceGas tax returns related to the SourceGas acquisition.

2017 Compared to 2016

Gross margin [a] increased over the prior year as a result of:

	(in millions)
12 months of SourceGas utilities' margins in 2017 compared to 10.5 months in 2016	$ 51.0
Other	0.8
Total increase (decrease) in Gross margin [a]	$ 51.8

(a) Non-GAAP measure

Operations and maintenance increased primarily due to additional operating costs of approximately $19 million for the acquired SourceGas utilities, reflecting a full twelve months of results in 2017 as compared to approximately 10.5 months in 2016. Employee-related expenses increased $6.2 million for the Black Hills legacy Gas Utilities as a result of prior year integration activities and transition expenses charged to Corporate and Other. An additional $1.6 million of indirect corporate costs are included at the Gas Utilities; these costs were previously charged to our Oil and Gas segment, now reported as discontinued operations. A variety of smaller items contribute to the partially offsetting decrease in operations and maintenance expenses.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities.

Interest expense, net increased primarily due to additional interest expense from the acquired SourceGas utilities.

Income tax: The effective tax rate increased in 2017 primarily due to additional tax expense of $6.8 million as a result of the TCJA enacted on December 22, 2017 and from a $2.2 million tax benefit recognized in the prior year primarily related to favorable flow-through adjustments recognized in accordance with prescribed regulatory treatment. Partially offsetting these is a $4.1 million tax benefit recognized in the current year from a true-up to the filed 2016 SourceGas tax returns related to the SourceGas acquisition.

Power Generation

Our Power Generation segment operating results for the years ended December 31 were as follows (in thousands):

	2018	Variance	2017	Variance	2016
Revenue	$ 88,952	$ (2,594)	$ 91,546	$ 415	$ 91,131
Operations and maintenance	33,727	1,345	32,382	(254)	32,636
Depreciation and amortization	6,913	920	5,993	1,889	4,104
Total operating expenses	40,640	2,265	38,375	1,635	36,740
Operating income	48,312	(4,859)	53,171	(1,220)	54,391
Interest expense, net	(4,995)	(2,159)	(2,836)	(1,061)	(1,775)
Other income (expense), net	(53)	1	(54)	(56)	2
Income tax benefit (expense)	(8,267)	(18,600)	10,333	27,462	(17,129)
Net income	34,997	(25,617)	60,614	25,125	35,489
Net income attributable to noncontrolling interest	(14,220)	(85)	(14,135)	(4,576)	(9,559)
Net income available for common stock	$ 20,777	$ (25,702)	$ 46,479	20,549	$ 25,930

FORM 10K

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

	2018	2017	2016
Contracted fleet plant availability:			
Gas-fired plants	99.4%	99.2%	99.2%
Coal-fired plants [(a)]	85.8%	96.9%	95.5%
Total	95.9%	98.6%	98.3%

(a) Wygen I experienced a planned outage in 2018.

2018 Compared to 2017

Net income available for common stock for the Power Generation segment was $21 million for the year ended December 31, 2018, compared to Net income available for common stock of $46 million for the same period in 2017. Revenue decreased in the current year due to a decrease in MWh sold, primarily from a planned outage at Wygen I. Operating expenses increased due to higher maintenance expenses primarily related to outage costs at Wygen I and higher depreciation. Interest expense increased from the same period in the prior year due to higher interest rates. The variance in tax expense is primarily due to a prior year $24 million tax benefit recognized from the revaluation of deferred tax liabilities in accordance with the TCJA enacted on December 22, 2017 partially offset by the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

2017 Compared to 2016

Net income available for common stock for the Power Generation segment was $46 million for the year ended December 31, 2017, compared to Net income available for common stock of $26 million for the same period in 2016. Revenue and operating expenses were comparable to the same period in the prior year and depreciation expense increased on non-leased assets. The variance to the prior year was primarily driven by a $24 million tax benefit recognized from the revaluation of deferred tax liabilities in accordance with the TCJA enacted on December 22, 2017.

Mining

Mining operating results for the years ended December 31 were as follows (in thousands):

	2018	Variance	2017	Variance	2016
Revenue	$ 68,033	$ 1,412	$ 66,621	$ 6,341	$ 60,280
Operations and maintenance	43,728	(1,154)	44,882	5,306	39,576
Depreciation, depletion and amortization	7,965	(274)	8,239	(1,107)	9,346
Total operating expenses	51,693	(1,428)	53,121	4,199	48,922
Operating income	16,340	2,840	13,500	2,142	11,358
Interest expense, net	(536)	(331)	(205)	172	(377)
Other income, net	164	(2,027)	2,191	(18)	2,209
Income tax benefit (expense)	(3,069)	(1,969)	(1,100)	2,037	(3,137)
Net income available for common stock	$ 12,899	$ (1,487)	$ 14,386	$ 4,333	$ 10,053

The following table provides certain operating statistics for the Mining segment (in thousands):

	2018	2017	2016
Tons of coal sold	4,085	4,183	3,817
Cubic yards of overburden moved [a]	8,970	9,018	7,916
Coal reserves at year-end	189,164	194,909	199,905

(a) Increase in overburden in 2018 and 2017 compared to 2016 was due to relocating mining operations to areas of the mine with higher overburden.

2018 Compared to 2017

Net income available for common stock for the Mining segment was $13 million for the year ended December 31, 2018, compared to Net income available for common stock of $14 million for the same period in 2017. Revenue increased primarily due to a 1% increase in price per ton sold. Current year revenue is also reflective of lease and rental revenue, previously reported in Other income, net. During the current period, approximately 50% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operating expenses decreased primarily due to lower major maintenance expenses and lower overburden removal. Other income, net decreased from the prior year due to the presentation change of lease and rental revenue to Revenue in the current year, previously reported in Other income, net. The variance in tax expense is primarily due to a prior year $2.7 million benefit resulting from revaluation of net deferred tax liabilities in accordance with the enactment of the TCJA on December 22, 2017, partially offset by the reduction in the federal corporate income tax rate from 35 percent to 21 percent from the TCJA, effective Jan. 1, 2018.

2017 Compared to 2016

Net income available for common stock for the Mining segment was $14 million for the year ended December 31, 2017, compared to Net income available for common stock of $10 million for the same period in 2016. The variance to the prior year was driven by an increase in revenue and lower tax expense, partially offset by higher operating expenses. Revenue increased due to a 10% increase in tons sold driven primarily by an 11-week outage at the Wyodak plant in 2016.

Operations and maintenance expenses increased due to higher equipment major maintenance, higher overburden moved and higher royalties and production taxes on increased revenues, partially offset by lower depreciation, depletion and amortization expense primarily due to lower plant in service and lower asset retirement obligation costs. The effective tax rate is lower in 2017 primarily due to a $2.7 million benefit resulting from revaluation of net deferred tax liabilities in accordance with the enactment of the TCJA on December 22, 2017.

Corporate and Other

Corporate and Other represents certain unallocated expenses for corporate and other administrative activities, interest and taxes that support our reportable operating segments. Below is a summary of operating expenses and tax (expenses) benefits included in Corporate and Other for the years ended December 31:

(in thousands)	2018	Variance	2017	Variance	2016
Operating (loss) [(a)]	$ (2,398)	$ 3,265	$ (5,663)	$ 59,075	$ (64,738)
Other income (expense):					
Interest (expense) income, net [(a)]	(1,597)	1,615	(3,212)	4,013	(7,225)
Other income (expense), net	375	1,305	(930)	264	(1,194)
Income tax benefit (expense)	(3,950)	28,854	(32,804)	(61,659)	28,855
Net income (loss) available for common stock	$ (7,570)	$ 35,039	$ (42,609)	$ 1,693	$ (44,302)

(a) Includes certain general and administrative and interest expenses that are not reported as discontinued operations.

2018 Compared to 2017

Net loss available for common stock was $(7.6) million for the year ended December 31, 2018, compared to Net loss available for common stock of $(43) million for the same period in 2017. The variance from the prior year was driven primarily by a decrease in income tax expense, as well as lower operating and interest expenses. The variance from the prior year was due to:

- Prior year tax expense of $35 million not attributable to our operating segments reflecting the revaluation of deferred tax balances as a result of the TCJA;
- Higher current year state income tax expense of $4.6 million;
- A decrease in corporate expenses from prior year acquisition costs; and
- Lower interest costs due to interest expenses originally charged to our Oil and Gas Segment in 2017 which were not reclassified to discontinued operations in 2017, and were allocated to our operating segments in 2018.

2017 Compared to 2016

Net (loss) available for common stock was $(43) million for the year ended December 31, 2017, compared to net (loss) available for common stock of $(44) million for the same period in 2016. The variance from the prior year was due to:

- Tax expense of $35 million not attributable to our operating segments reflecting the revaluation of deferred tax balances as a result of the TCJA;
- A decrease in after-tax acquisition and transition expenses of approximately $36 million, driven by lower external acquisition costs and lower internal labor attributed to the SourceGas Acquisition;
- As a result of the Oil and Gas segment being reported as discontinued operations in 2017, indirect operating costs that would have been charged to this segment were reallocated to other business segments in 2017. These same costs in 2016 are reported as Corporate and Other;
- A decrease of approximately $4.4 million in tax benefits; and
- A decrease in other corporate expenses.

Discontinued Operations

Oil and Gas operating results included in discontinued operations for the years ended December 31 were as follows (in thousands):

	2018	Variance	2017	Variance	2016
Revenue	$ 5,897	$ (19,485)	$ 25,382	$ (8,676)	$ 34,058
Operations and maintenance	11,014	(11,858)	22,872	(4,315)	27,187
Depreciation, depletion and amortization	1,300	(6,221)	7,521	(5,989)	13,510
Loss on sale of asset	3,259	3,259	—	—	—
Impairment of long-lived assets	—	(20,385)	20,385	(86,572)	106,957
Total operating expenses	15,573	(35,205)	50,778	(96,876)	147,654
Operating (loss)	(9,676)	15,720	(25,396)	88,200	(113,596)
Interest income (expense), net	(19)	(200)	181	(517)	698
Other income (expense), net	190	487	(297)	(407)	110
Income tax benefit (expense)	2,618	(5,795)	8,413	(40,213)	48,626
(Loss) from discontinued operations available for common stock	$ (6,887)	$ 10,212	$ (17,099)	$ 47,063	$ (64,162)

2018 Compared to 2017

Net loss from discontinued operations was $(6.9) million for 2018, compared to Net loss from discontinued operations of $(17) million for the same period in 2017. The variance is driven by lower revenues due to property sales and higher losses on sales of operating assets, partially offset by lower oil and gas operating expenses and lower employee costs. Current year depreciation expense is representative of the amortization of the remaining book value of accounting software. Depreciation and depletion expense was recorded under full cost accounting, which ceased November 1, 2017 due to reclassification to assets held for sale. There were no impairments during 2018 compared to a $20 million non-cash fair value impairment of assets held for sale in 2017.

2017 Compared to 2016

Net loss from discontinued operations was $(17) million for 2017, compared to Net loss from discontinued operations of $(64) million for the same period in 2016. The variance is driven by decreased revenues primarily due to lower commodity prices and decreased production offset by lower operating expenses due to lower employee costs as a result of reduced staffing. Depreciation and depletion decreased due to the reduction of our full cost pool resulting from 2016 ceiling test impairments and no depletion recorded on assets held for sale beginning on November 1, 2017.

In 2017, we recorded a $20 million non-cash fair value impairment of assets held for sale compared to 2016 impairments that included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $93 million, offset by lower income tax benefit in 2017 compared to 2016. Interest expense decreased primarily due to lower capitalized interest expense in 2017 compared to 2016. Each period reflects a tax benefit. The effective tax rate for 2016 was impacted by a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

Critical Accounting Policies Involving Significant Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments, or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

The following discussion of our critical accounting estimates should be read in conjunction with Note 1, "Business Description and Significant Accounting Policies" of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Regulation

Our utility operations are subject to regulation with respect to rates, service area, accounting, and various other matters by state and federal regulatory authorities. The accounting regulations provide that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effects in the manner of which independent third-party regulators establish rates. Regulatory assets generally represent incurred or accrued costs that have been deferred when future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

Management continually assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders, and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

Goodwill

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Our annual goodwill impairment testing date is as of October 1, which aligns our testing date with our financial planning process.

Accounting standards for testing goodwill for impairment require a two-step process be performed to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount exceeds fair value under the first step, then the second step of the impairment test is performed to measure the amount of any impairment loss.

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We have determined that the reporting units for goodwill impairment testing are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation, 2) estimates of long-term growth rates for our businesses, 3) the determination of an appropriate weighted-average cost of capital or discount rate, and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries. Varying by reporting unit, weighted average cost of capital in the range of 5% to 6% and long-term growth rate projections in the 1% to 2% range were utilized in the goodwill impairment test performed in the fourth quarter of 2018. Although 1% to 2% was used for a long-term growth rate projection, the short-term projected growth rate is higher with planned recovery of capital investments through rider mechanisms and rate reviews, as well as other improved efficiency and cost reduction initiatives. Under the market approach, we estimate fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, we add a reasonable control premium when calculating fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants.

The estimates and assumptions used in the impairment assessments are based on available market information, and we believe they are reasonable. However, variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. For the years ended December 31, 2018, 2017, and 2016, there were no impairment losses recorded. At December 31, 2018, the fair value substantially exceeded the carrying value at all reporting units.

Pension and Other Postretirement Benefits

As described in Note 18 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan, and several defined post-retirement healthcare plans and non-qualified retirement plans. A Master Trust holds the assets for the pension plan. Trusts for the funded portion of the post-retirement healthcare plans have also been established.

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rates, healthcare cost trend rates, expected return on plan assets, compensation increases, retirement rates and mortality rates. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions determined by management and used by actuaries in calculating the amounts. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

The pension benefit cost for 2019 for our non-contributory funded pension plan is expected to be $2.1 million compared to $6.3 million in 2018. The decrease in pension benefit cost is driven primarily by an increase in the discount rate.

The effect of hypothetical changes to selected assumptions on the pension and other postretirement benefit plans would be as follows in thousands of dollars:

		December 31,	
Assumptions	Percentage Change	2018 Increase/(Decrease) PBO/APBO [(a)]	2019 Increase/(Decrease) Expense - Pretax
Pension			
Discount rate [(b)]	+/- 0.5	(25,221)/27,665	(3,597)/3,906
Expected return on assets	+/- 0.5	N/A	(2,033)/2,035
OPEB			
Discount rate [(b)]	+/- 0.5	(2,525)/2,743	89/(98)
Expected return on assets	+/- 0.5	N/A	(38)/38

(a) Projected benefit obligation (PBO) for the pension plan and accumulated postretirement benefit obligation (APBO) for OPEB plans.
(b) Impact on service cost, interest cost and amortization of gains or losses.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain acquired subsidiaries file as a separate consolidated group. Each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company's future results of operations, financial position, or cash flows.

The Company has revalued the deferred income taxes at the 21% federal tax rate as of December 31, 2017 and as a result, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. As of December 31, 2018 we have a regulatory liability associated with TCJA related items of $311 million, completing the revaluation of deferred taxes pursuant to the TCJA. A significant portion of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets. As of December 31, 2018, the Company has amortized $2.1 million of regulatory liability associated with TCJA related items. The portion that was eligible for amortization under the average rate assumption method in 2018, but is awaiting resolution of the treatment of these amounts in future regulatory proceedings, has not been recognized and may be refunded in customer rates at any time in accordance with the resolution of pending or future regulatory proceedings.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

See Note 15 in the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Business Combinations

We record acquisitions in accordance with ASC 805, *Business Combinations,* with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, *Business Combinations* requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Pertaining to our 2016 acquisition of SourceGas, substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 in the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Accounting for Oil and Gas Activities

We completed the divestiture of our Oil and Gas segment in 2018. For 2016, our Oil and Gas Activities were significant. Accounting for oil and gas activities in 2017 and 2016 was a significant accounting policy and included significant accounting estimates as disclosed below.

Impairment testing of assets held for sale

In 2017, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. For the assets that have not yet been sold, the estimated fair value of our oil and gas assets was determined using the market approach. The market approach was based on the fourth quarter 2017 sale of our Powder River Basin assets and other sale transactions of our other properties.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets and liabilities could be different using different estimates and assumptions in the valuation techniques used. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale are reasonable based on the information that was known when the estimates were made.

At December 31, 2017, the fair value of our held-for-sale assets was less than our carrying value, which required an after-tax write down of $13 million. For additional information, see Note 21 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Full Cost Method of Accounting for Oil and Gas Activities

Prior to the November 1, 2017 decision to divest our oil and gas business, we accounted for oil and gas activities under the full cost method of accounting, whereby all productive and nonproductive costs related to acquisition, exploration, development, abandonment and reclamation activities were capitalized. Accounting for oil and gas activities is subject to industry-specific rules. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a ceiling test that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon SEC-defined prices for oil and gas as of the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling throughout 2016, which required an after-tax write-down of $58 million for the year ended December 31, 2016. Reserves in 2016 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties adjusted for contracted price changes.

Oil, Natural Gas, and Natural Gas Liquids Reserve Estimates

Estimates of our proved crude oil, natural gas and NGL reserves are based on the quantities of each that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prior to November 1, 2017, an independent petroleum engineering company prepared reports that estimate our proved oil, natural gas and NGL reserves annually. The accuracy of any crude oil, natural gas and NGL reserve estimate is a function of the quality of available data, engineering judgment and geological interpretation. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and work-over costs, all of which may in fact vary considerably from actual results. In addition, as crude oil, natural gas and NGL prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Estimates for our crude oil, natural gas, and NGL reserves are used throughout our financial statements. For example, since we used the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporated the estimated unit-of-production attributable to the estimates of proved reserves. Under full-cost accounting, the net book value of our crude oil and gas properties was also subject to a "ceiling" limitation based in large part on the value of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Liquidity and Capital Resources

OVERVIEW

Our company requires significant cash to support and grow our businesses. Our predominant source of cash is supplied by our operations and supplemented with corporate financings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate. As discussed in more detail below under income taxes, we experienced an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers.

The most significant uses of cash are for our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices, as well as during the summer construction season.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, regulatory liabilities, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

The following table provides an informational summary of our financial position as of December 31 (dollars in thousands):

Financial Position Summary		2018		2017
Cash and cash equivalents	$	20,776	$	15,420
Restricted cash and equivalents	$	3,369	$	2,820
Notes payable	$	185,620	$	211,300
Short-term debt, including current maturities of long-term debt	$	5,743	$	5,743
Long-term debt [(a)]	$	2,950,835	$	3,109,400
Stockholders' equity	$	2,181,588	$	1,708,974
Ratios				
Long-term debt ratio		57%		64%
Total debt ratio		59%		66%

(a) Carrying amount of long-term debt is net of deferred financing costs.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow. However, the potential for unforeseen events affecting cash needs will continue to exist.

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty. At December 31, 2018, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts.

Weather Seasonality, Commodity Pricing and Associated Hedging Strategies

We manage liquidity needs through hedging activities, primarily in connection with seasonal needs of our utility operations (including seasonal peaks in fuel requirements), interest rate movements and commodity price movements.

Utility Factors

Our cash flows, and in turn liquidity needs in many of our regulated jurisdictions, can be subject to fluctuations in weather and commodity prices. Since weather conditions are uncontrollable, we have implemented commission-approved natural gas hedging and storage programs in many of our regulated jurisdictions to mitigate significant changes in natural gas commodity pricing. We target hedging of approximately 40% to 70% of our forecasted natural gas supply using options, futures and basis swaps.

Interest Rates

Several of our debt instruments have a variable interest rate component which can change significantly depending on the economic climate. We don't have any interest rate swap agreements at December 31, 2018; 84% of our interest rate exposure has been mitigated through fixed interest rates.

Federal and State Regulations

Federal

We are structured as a utility holding company which owns several regulated utilities. Within this structure, we are subject to various regulations by our commissions that can influence our liquidity. As an example, the issuance of debt by our regulated subsidiaries and the use of our utility assets as collateral generally require prior approval of the state regulators in the state in which the utility assets are located. Furthermore, as a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is subordinate to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

Income Tax

The TCJA required revaluation of federal deferred tax assets and liabilities using the new lower corporate tax rate of 21%. We have reached agreements with regulators in six states and are working with regulators in our seventh state, as well as FERC. Our working capital requirements increased as a result of complying with the TCJA and providing the benefits of the TCJA to customers, negatively impacted our cash flows by approximately $40 million to $45 million annually for the next several years. See Notes 1 and 13 for more information on regulatory matters and Note 15 for revaluations of deferred taxes under the TCJA.

Acceleration of depreciation for tax purposes, including 50% bonus depreciation, was previously available for certain property placed in service through September 27, 2017. The TCJA enacted 100% bonus depreciation generally to qualifying property acquired and placed in service after September 27, 2017 and before January 1, 2023. After 2022, bonus depreciation would reduce 20% per year for qualifying property placed in service through 2026. The provision expands the property that is eligible for this immediate expensing by repealing the requirement that the original use of the property begin with the taxpayer. Instead, the property is eligible for the additional depreciation if it is the taxpayer's first use. Under the provision, qualified property eligible for bonus depreciation, including immediate expensing, does not include any property used by a regulated public utility company or any property used in a real property trade or business. These depreciation provisions resulted in cash tax benefits for BHC as indicated in the table below:

(in millions)	2018	2017	2016
Tax benefit	$—	$37	$81

In addition, bonus depreciation will apply to qualifying property whose construction and completion period encompasses multiple tax years. The exception being with respect to costs that would be incurred in 2027 when, under current law, bonus depreciation is scheduled to expire.

The effect of additional depreciation deductions as a result of bonus depreciation will serve to reduce taxable income and contribute to extending the tax loss carryforwards from being fully utilized until 2022 based on current projections.

See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

CASH GENERATION AND CASH REQUIREMENTS

Cash Generation

Our primary sources of cash are generated from operating activities, our five-year Revolving Credit Facility expiring in 2023, our CP Program and our ability to access the public and private capital markets through debt and equity securities offerings when necessary.

Cash Collateral

Under contractual agreements and exchange requirements, BHC or its subsidiaries have collateral requirements, which if triggered, require us to post cash collateral with the counterparty to meet these obligations.

We have posted the following amounts of cash collateral with counterparties at December 31 (in thousands):

Purpose of Cash Collateral	2018	2017
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$ 7,266	$ 7,694
Natural Gas Over-the-Counter Swaps Pursuant to Master Agreements for Derivative Instruments	—	562
Total Cash Collateral	$ 7,266	$ 8,256

DEBT

Financing Transactions and Short-Term Liquidity

Our principal liquidity sources to meet day-to-day operating cash requirements are cash from operations, our CP Program and our corporate Revolving Credit Facility.

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. See Note 7 for more information.

We have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. See Note 7 for more information.

Our Revolving Credit Facility had the following borrowings, outstanding letters of credit, and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Revolver Borrowings at December 31, 2018	CP Program Borrowings at December 31, 2018	Letters of Credit at December 31, 2018	Available Capacity at December 31, 2018
Revolving Credit Facility	July 30, 2023	$ 750	$ —	$ 186	$ 22	$ 542

The weighted average interest rate on CP Program borrowings at December 31, 2018 was 2.88%. Revolving Credit Facility and CP Program financing activity for the twelve months ended December 31, 2018 was:

		(dollars in millions)
Maximum amount outstanding - commercial paper (based on daily outstanding balances)	$	231
Maximum amount outstanding - revolving credit facility (based on daily outstanding balances)	$	—
Average amount outstanding - commercial paper (based on daily outstanding balances) [(a)]	$	120
Average amount outstanding - revolving credit facility (based on daily outstanding balances)	$	—
Weighted average interest rates - commercial paper		1.97%
Weighted average interest rates - revolving credit facility		—%

(a) No commercial paper was issued from November 1, 2018 to December 11, 2018 due to excess cash on hand from the Equity Units settlement until we paid off the $250 million, 2.5% Senior unsecured notes due January 11, 2019.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. Under the Revolving Credit Facility, our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness (which includes letters of credit and certain guarantees issued), by (ii) Capital, which is Consolidated Indebtedness plus Consolidated Net Worth (which excludes noncontrolling interests in subsidiaries). Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of December 31, 2018.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Capital Resources

Our principal sources for our long-term capital needs have been issuances of long-term debt securities by the Company and its subsidiaries along with proceeds obtained from public and private offerings of equity and proceeds from our ATM equity offering program.

Financing Activities

Financing activities in 2018 consisted of the following:

- Short-term borrowings from our CP Program.

- On December 12, 2018, we paid off the $250 million, 2.5% senior unsecured notes due January 11, 2019. Proceeds from the November 1, 2018 Equity Unit conversion were used to repay this obligation.

- On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued November 23, 2015. Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of approximately $299 million in exchange for approximately 6.372 million shares of common stock. See Note 12 for more information.

- On August 17, 2018, we completed a public debt offering of $400 million principal amount, 4.350% senior unsecured notes due 2033. The proceeds were used to repay the $299 million principal amount of our RSNs due 2028 and pay down short-term debt. Through this offering, we successfully remarketed the $299 million principal amount of the existing subordinated notes, which were originally issued as a part of the Company's Equity Units on November 23, 2015. See Note 6 for more information.

- On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at December 31, 2018, will now mature July 30, 2020 and has substantially similar terms and covenants as the amended and restated Revolving Credit Facility. See Note 6 for more information.

- We did not issue any shares of common stock under our ATM equity offering program in 2018.

Financing activities for 2017 consisted of short-term borrowings from our Revolving Credit Facility and CP Program. We also made principal payments of $50 million each on May 16, 2017 and July 17, 2017 on our Corporate term loan due August 9, 2019. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan. On August 4, 2017, we renewed the ATM equity offering program which reset the size of the ATM equity offering program to an aggregate value of up to $300 million. We did not issue any shares of common stock under our ATM equity offering program during 2017.

Future Financing Plans

We will evaluate refinancing options for our $200 million senior notes due July 15, 2020 and the $300 million Corporate term loan due July 30, 2020.

Cross-Default Provisions

Our $300 million and $13 million Corporate term loans contain cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to make timely payments of debt obligations or triggered other default provisions under any debt agreement totaling, in the aggregate principal amount of $50 million or more that permits the acceleration of debt maturities or mandatory debt prepayment. Our Revolving Credit Facility contains the same provisions and a threshold principal amount is $50 million.

The Revolving Credit Facility prohibits us from paying cash dividends if we are in default or if paying dividends would cause us to be in default.

Equity

Based on our current disclosed capital spending forecast, we anticipate the need for issuing $25 million to $50 million of equity annually, in 2019 and 2020 under our ATM equity offering program. Aside from our ATM equity offering program, we do not anticipate any other need to further access the equity capital markets in the next three years.

Shelf Registration

We have an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. We renewed our shelf registration on August 4, 2017. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2018, we had approximately 60 million shares of common stock outstanding and no shares of preferred stock outstanding.

Common Stock Dividends

Future cash dividends, if any, will be dependent on our results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated and approved by our Board of Directors.

On January 30, 2019, our Board of Directors declared a quarterly dividend of $0.505 per share or an annualized equivalent dividend rate of $2.02 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share:

	2018	2017	2016
Dividend Payout Ratio	40%	50%	65%
Dividends Per Share	$1.93	$1.81	$1.68

Our three-year compound annualized dividend growth rate was 6.0% and all dividends were paid out of available operating cash flows.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act.

As a result of our holding company structure, our right as a common shareholder to receive assets from any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders. See additional information in Note 6 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not comply with certain financial or other covenants. See additional information in Note 7 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of December 31, 2018, we were in compliance with these covenants.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utilities and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option, borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (3.056% and 1.962% at December 31, 2018 and 2017, respectively). While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, money pool balances included (in thousands):

	Borrowings From Money Pool Outstanding	
Subsidiary	2018	2017
Black Hills Utility Holdings	$ 48,056	$ 35,693
South Dakota Electric	38,690	13,397
Wyoming Electric	24,704	15,290
Total Money Pool borrowings from Parent	$ 111,450	$ 64,380

FORM 10K

CASH FLOW ACTIVITIES

The following table summarizes our cash flows (in thousands):

		2018		2017		2016
Cash provided by (used in)						
Operating activities	$	488,811	$	428,261	$	320,479
Investing activities	$	(465,849)	$	(317,118)	$	(1,588,165)
Financing activities	$	(17,057)	$	(108,695)	$	840,998

2018 Compared to 2017

Operating Activities:

Net cash provided by operating activities was $61 million higher than in 2017. The variance to the prior year was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $7 million lower than prior year driven primarily by impacts of customer refunds related to the TCJA tax decrease which lowered current year revenue;
- Net inflow from operating assets and liabilities was $62 million higher than prior year, primarily attributable to:
    - Cash inflows increased by approximately $34 million as a result of changes in accounts payable and accrued liabilities, driven by the impact of energy commodity prices on our accounts payable, partially offset by the expiration of accrued contract payables related to Equity Units;
    - Cash outflows increased by approximately $43 million compared to the prior year as a result of higher accounts receivable driven by higher revenues, energy delivered and energy commodity prices; and
    - Cash inflows increased by approximately $72 million primarily as a result of changes in our current regulatory assets driven by lower fuel cost adjustments and the impact of lower commodity price on our regulatory assets and from an increase in current regulatory liabilities driven by cash collections of income taxes from customer bills in excess of current tax rates subsequent to the TCJA that will be refunded in the future;
- Cash outflows decreased by approximately $15 million due to additional pension contributions made in the prior year;
- Cash inflows increased approximately $15 million for other operating activities compared to the prior year primarily due to the long-term expiration of accrued contract payables related to Equity Units; and
- Cash outflows increased approximately $25 million due to operating activities of discontinued operations.

Investing Activities:

Net cash used in investing activities was $466 million in 2018, compared to net cash used in investing activities of $317 million in 2017 for a variance of $149 million. This variance was primarily due to:

- Capital expenditures of approximately $458 million in 2018 compared to $326 million in 2017. The $132 million increase from the prior year was due to higher capital expenditures at our Electric and Gas Utilities which included additional transmission investments, and higher programmatic integrity capital at our Gas Utilities. Capital expenditures increased at our Power Generation segment due to the Busch Ranch I purchase, and from investments made to Wygen I. Capital investments also increased at our Mining segment as they purchased a new mining shovel in 2018.
- A $24 million investment partially offset by a $13 million increase in net cash provided by investing activities from discontinued operations.

Financing Activities:

Net cash used in financing activities was $17 million in 2018, a decrease of $92 million from 2017 primarily due to the following:

- Payments of long-term debt increased by $749 million due to current year payments on the $300 million term loan refinanced in July 2018, the retirement of $299 million of RSNs in August 2018 and the retirement of $250 million Senior unsecured notes in December 2018, compared to $100 million of principal payments made on term loans in the prior year;

- Long-term borrowings increased by $700 million due to the issuance of $400 million senior secured notes in August 2018 and the refinancing of our $300 million unsecured term loan in July 2018;

- Gross proceeds of approximately $299 million received in exchange for approximately 6.372 million shares of common stock from the Equity Unit conversion;

- Net short-term debt payments increased by $140 million as a result of using proceeds from the Equity Unit conversion to pay down short-term debt;

- Cash dividends on common stock of $107 million were paid in 2018 compared to $97 million paid in 2017;

- Cash outflows for other financing activities increased by approximately $4.3 million driven primarily by higher financing costs incurred in the July 30, 2018 and August 17, 2018 debt transactions.

<u>2017 Compared to 2016</u>

Operating Activities:

Net cash provided by operating activities was $108 million higher than in 2016. The variance to the prior year was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $68 million higher than prior year;

- Net outflow from operating assets and liabilities was $16 million lower than prior year, primarily attributable to:

    - Cash outflows decreased by approximately $4.8 million as a result of changes in accounts payable and accrued liabilities driven by changes in working capital requirements;

    - Cash outflows decreased by approximately $20 million compared to the prior year as a result of lower accounts receivable due to warmer weather partially offset by higher natural gas inventory; and

    - Cash outflows increased by approximately $9.5 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts compared to the same period in the prior year;

- Cash outflows decreased by approximately $29 million as a result of interest rate swap settlements;

- Cash outflows increased by approximately $14 million due to additional pension contributions made in 2017;

- Cash outflows increased approximately $7.8 million for other operating activities compared to the prior year; and

- Cash inflows decreased approximately $17 million due to operating activities of discontinued operations.

Investing Activities:

Net cash used in investing activities was $317 million in 2017, compared to net cash used in investing activities of $1.6 billion in 2016 for a variance of $1.3 billion. This variance was primarily due to:

- In 2016 cash outflows included approximately $1.1 billion for the acquisition of SourceGas, net of $760 million long-term debt assumed (see Note 2 in Item 8 of Part II of this Annual Report on Form 10-K);

- Capital expenditures of approximately $326 million in 2017 compared to $455 million in 2016. The $129 million variance to the prior year was due primarily to higher prior year capital expenditures at our Electric Utilities from generation investments at Colorado Electric; and

- Cash inflows increased approximately $16 million due to investing activities of discontinued operations.

Financing Activities:

Net cash used in financing activities was $109 million in 2017, an increase of $950 million from 2016 primarily due to the following:

- Long-term borrowings decreased by $1.8 billion due to the 2016 financings which consisted of $693 million of net proceeds from the August 19, 2016 public debt offering used to refinance the debt assumed in the SourceGas Acquisition, $500 million of proceeds from the August 9, 2016 term loan, $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract;

- Payments on long-term debt decreased by $1.1 billion due to the 2016 refinancing of the $760 million of long-term debt assumed in the SourceGas Acquisition and lower current year payments on term loans, $106 million paid on term loans in 2017 compared to $400 million paid on term loans in 2016;

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP that took place in 2016 (see Note 12 in Item 8 of Part II of this Annual Report on Form 10-K);

- Proceeds from common stock issuances decreased by $117 million primarily from issuing common stock under our ATM equity offering program in 2016;

- Net short-term borrowings increased by $95 million primarily due to CP borrowings used to pay down long-term debt;

- Cash dividends on common stock of $97 million were paid in 2017 compared to $88 million paid in 2016;

- In 2017, distributions to noncontrolling interests increased by $8.8 million compared to 2016; and

- Cash outflows for other financing activities decreased by approximately $16 million driven primarily by higher financing costs from the 2016 debt offerings and refinancings compared to a payment of $5.6 million for a redeemable noncontrolling interest in March 2017.

CAPITAL EXPENDITURES

Capital expenditures are a substantial portion of our cash requirements each year and we continue to forecast a robust capital expenditure program during the next four years. See Key Elements of our Business Strategy above in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations for forecasted capital expenditure requirements.

Historically, a significant portion of our capital expenditures relate primarily to assets that may be included in utility rate base, and if considered prudent by regulators, can be recovered from our utility customers. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate and are subject to rate agreements. During 2018, our Electric Utilities' capital expenditures included improvements to generating stations, transmission and distribution lines. Capital expenditures associated with our Gas Utilities are primarily to improve or expand the existing gas distribution network. In 2018, we also added renewable generation at our Power Generation segment, and upgraded equipment at our Mining segment. We believe that cash generated from operations, borrowings on our CP Program and Revolving Credit Facility, and equity issuances under our ATM equity offering program, if necessary, will be adequate to fund ongoing capital expenditures.

Historical Capital Requirements

Our primary capital requirements for the three years ended December 31 were as follows (in thousands):

	2018	2017	2016
Property additions: [a]			
Electric Utilities	$ 152,524	$ 138,060	$ 258,739
Gas Utilities	288,438	184,389	173,930
Power Generation	30,945	1,864	4,719
Mining	18,794	6,708	5,709
Corporate and Other	11,723	6,668	17,353
Capital expenditures before discontinued operations	502,424	337,689	460,450
Discontinued operations	2,402	23,222	6,669
Total capital expenditures	504,826	360,911	467,119
Common stock dividends	106,591	96,744	87,570
Maturities/redemptions of long-term debt	854,743	105,743	1,164,308
Total capital requirements	$ 1,466,160	$ 563,398	$ 1,718,997

(a) Includes accruals for property, plant and equipment.

CREDIT RATINGS AND COUNTERPARTIES

Financing for operational needs and capital expenditure requirements not satisfied by operating cash flows depends upon the cost and availability of external funds through both short and long-term financing. The inability to raise capital on favorable terms could negatively affect the Company's ability to maintain or expand its businesses. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the Company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. BHC notes that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2018:

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

(a) On August 9, 2018, S&P upgraded to BBB+ rating and revised the outlook to Stable.
(b) On December 12, 2018, Moody's affirmed Baa2 rating and maintained a Stable outlook.
(c) On October 11, 2018, Fitch affirmed BBB+ rating and maintained a Stable outlook.

Certain of our fees and our interest rates under various bank credit agreements are based on our credit ratings at all three rating agencies. If all of our ratings are at the same level, or two of our ratings are the same level and one differs, these fees and interest rates will be based on the ratings that are at the same level. If all of our ratings are at different levels, these fees and interest rates will be based on the middle level. Currently, our Fitch and S&P ratings are at the same level, and our Moody's rating is one level below. Therefore, if Fitch or S&P downgraded our senior unsecured debt, we will be required to pay higher fees and interest rates under these bank credit agreements.

The following table represents the credit ratings of South Dakota Electric at December 31, 2018:

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

(a) On August 9, 2018, S&P upgraded to A rating.
(b) On December 12, 2018, Moody's affirmed A1 rating.
(c) On October 11, 2018, Fitch affirmed A rating.

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs, or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at December 31, 2018. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt[a][b]	$ 2,982,776	$ 5,743	$ 514,178	$ 525,000	$ 1,937,855
Unconditional purchase obligations[c]	737,507	151,110	259,073	178,961	148,363
Operating lease obligations[d]	4,076	1,052	808	440	1,776
Other long-term obligations[e]	56,800	—	—	—	56,800
Employee benefit plans[f]	138,510	18,144	56,684	38,315	25,367
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions	3,583	—	—	—	3,583
CP Program	185,620	185,620	—	—	—
Total contractual cash obligations[g]	$ 4,108,872	$ 361,669	$ 830,743	$ 742,716	$ 2,173,744

(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) The following amounts are estimated for interest payments over the next five years which are not included within the long-term debt balances presented: $130 million in 2019, $126 million in 2020, $108 million in 2021, $108 million in 2022 and $102 million in 2023. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2018.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas transportation and storage agreements. The energy charges under the PPAs are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2018 and price assumptions using existing prices at December 31, 2018. Our transmission obligations are based on filed tariffs as of December 31, 2018.

(d) Includes operating leases associated with several office buildings, warehouses and call centers, equipment and vehicles.

(e) Includes estimated asset retirement obligations associated with our Electric Utilities, Gas Utilities and Mining segments as discussed in Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

(f) Represents both estimated employer contributions to Defined Benefit Pension Plan and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2028.

(g) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including commodity related contracts that have a negative fair value at December 31, 2018. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; and (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table.

Our Gas Utility segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. In addition, a portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. As of December 31, 2018, we are committed to purchase 10.2 million MMBtu, 3.7 million MMBtu, 3.7 million MMBtu, 1.8 million MMBtu and 0.0 million MMBtu in each of the years from 2019 to 2023, respectively.

Off-Balance Sheet Commitments

Guarantees

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit. We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2018, we had outstanding guarantees as indicated in the table below. For more information on these guarantees, see Note 20 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2018	Year Expiring
Indemnification for subsidiary reclamation/surety bonds [(a)]	$ 54,683	Ongoing
Contract performance guarantee [(b)]	39,807	December 2019
	$ 94,490	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.
(b) BHC has guaranteed the full and complete payment and performance on behalf of Black Hills Electric Generation for construction of the Busch Ranch II Wind Farm. The guarantee terminates when BHC or Black Hills Electric Generation has paid for and performed all guaranteed obligations. The guarantee decreases as progress payments are made.

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $22 million in letters of credit issued under our Revolving Credit Facility at December 31, 2018.

Market Risk Disclosures

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures.

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

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for several of our gas-fired generation assets, which include market fluctuations due to unpredictable factors such as weather, market speculation, pipeline constraints, and other factors that may impact natural gas supply and demand;

- Interest rate risk associated with our variable debt as described in Notes 6 and 7 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Our exposure to these market risks is also affected by other factors including the size, duration and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates and the liquidity of the related interest rate and commodity markets.

The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee and reviewed by the Audit Committee of our Board of Directors. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities and employee conduct. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Electric and Gas Utilities

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in six states. Our utilities have ECA or GCA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to "true-up" billed amounts to match the actual natural gas cost we incurred. In Colorado, Montana, South Dakota and Wyoming, we have a mechanism for our regulated electric utilities that serves a purpose similar to the GCAs for our regulated gas utilities. To the extent that our fuel and purchased power costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer. These adjustments are subject to periodic prudence reviews by the state utility commissions. See additional information in Note 9 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

The fair value of our Electric and Gas Utilities derivative contracts at December 31 is summarized below (in thousands):

	2018	2017
Net derivative (liabilities) assets	$ (2,214)	$ (6,644)
Cash collateral	7,266	8,256
	$ 5,052	$ 1,612

Wholesale Power

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

Historically, we have engaged in activities to manage risks associated with changes in interest rates. We utilized pay-fixed interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt refinancings. At December 31, 2018, we had no interest rate swaps in place.

Further details of past swap agreements are set forth in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

The table below presents principal amounts and related weighted average interest rates by year of maturity for our long-term debt obligations, including current maturities (dollars in thousands):

	2019	2020	2021	2022	2023	Thereafter	Total
Long-term debt							
Fixed rate[(a)]	$ 5,743	$ 205,743	$ 1,435	$ —	$ 525,000	$ 1,925,000	$ 2,662,921
Average interest rate	2.32%	5.78%	2.32%	—%	4.25%	3.53%	4.5%
Variable rate	$ —	$ 300,000	$ 7,000	$ —	$ —	$ 12,855	$ 319,855
Average interest rate [(b)]	—%	3.16%	1.73%	—%	—%	1.77%	3.07%
Total long-term debt	$ 5,743	$ 505,743	$ 8,435	$ —	$ 525,000	$ 1,937,855	$ 2,982,776
Average interest rate [(b)]	2.32%	4.22%	1.83%	—%	4.25%	3.52%	4.34%

(a) Excludes unamortized premium or discount.
(b) Interest rates as of December 31, 2018.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Risk Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

We seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot provide assurance that we will continue to experience the same credit loss rates that we have in the past, or that an investment grade counterparty will not default sometime in the future.

Our credit exposure at December 31, 2018 was concentrated primarily among retail utility customers, investment grade companies, municipal cooperatives and federal agencies.

New Accounting Pronouncements

See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2018 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management’s Report on Internal Control over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our 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.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2018, based on the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission “COSO”. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of December 31, 2018.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation’s financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2018. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on the Financial Statements

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 19, 2019

We have served as the Company’s auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on Internal Control over Financial Reporting

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2018, of the Company, and our report dated February 19, 2019 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

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 19, 2019

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Year ended	December 31, 2018	December 31, 2017	December 31, 2016
	(in thousands, except per share amounts)		
Revenue	$ 1,754,268	$ 1,680,266	$ 1,538,916
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	625,610	563,288	499,132
Operations and maintenance	481,706	454,605	426,603
Depreciation, depletion and amortization	196,328	188,246	175,533
Taxes - property and production	51,746	51,578	46,160
Other operating expenses	1,841	5,813	55,307
Total operating expenses	1,357,231	1,263,530	1,202,735
Operating income	397,037	416,736	336,181
Other income (expense):			
Interest charges -			
Interest expense incurred net of amounts capitalized (including amortization of debt issuance costs, premiums and discounts)	(143,720)	(140,533)	(139,091)
Allowance for funds used during construction - borrowed	2,104	2,415	2,981
Interest income	1,641	1,016	1,429
Allowance for funds used during construction - equity	619	2,321	3,270
Other income (expense), net	(1,799)	(213)	1,124
Total other income (expense)	(141,155)	(134,994)	(130,287)
Income before income taxes	255,882	281,742	205,894
Income tax benefit (expense)	23,667	(73,367)	(59,101)
Income from continuing operations	279,549	208,375	146,793
Net (loss) from discontinued operations	(6,887)	(17,099)	(64,162)
Net income	272,662	191,276	82,631
Net income attributable to noncontrolling interest	(14,220)	(14,242)	(9,661)
Net income available for common stock	$ 258,442	$ 177,034	$ 72,970
Amounts attributable to common shareholders:			
Net income from continuing operations	$ 265,329	$ 194,133	$ 137,132
Net (loss) from discontinued operations	(6,887)	(17,099)	(64,162)
Net income (loss) available for common stock	$ 258,442	$ 177,034	$ 72,970
Earnings (loss) per share of common stock, Basic -			
Earnings from continuing operations	$ 4.88	$ 3.65	$ 2.64
(Loss) from discontinued operations	(0.13)	(0.32)	(1.23)
Total earnings per share of common stock, Basic	$ 4.75	$ 3.33	$ 1.41
Earnings (loss) per share of common stock, Diluted -			
Earnings from continuing operations	$ 4.78	$ 3.52	$ 2.57
(Loss) from discontinued operations	(0.12)	(0.31)	(1.20)
Total earnings per share of common stock, Diluted	$ 4.66	$ 3.21	$ 1.37
Weighted average common shares outstanding:			
Basic	54,420	53,221	51,922
Diluted	55,486	55,120	53,271

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended	December 31, 2018	December 31, 2017	December 31, 2016
		(in thousands)	
Net income	$ 272,662	$ 191,276	$ 82,631
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $(660), $1,030 and $757, respectively)	2,155	(1,890)	(1,738)
Benefit plan liability adjustments - prior service (costs) (net of tax of $0, $0 and $107, respectively)	—	—	(247)
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(586), $(585) and $(600), respectively)	1,901	1,072	1,378
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $43, $69 and $67, respectively)	(135)	(128)	(154)
Derivative instruments designated as cash flow hedges:			
Net unrealized gains (losses) on interest rate swaps (net of tax of $0, $0 and $10,920, respectively)	—	—	(20,302)
Reclassification of net realized (gains) losses on settled/ amortized interest rate swaps (net of tax of $(599), $(1,029) and $(1,365), respectively)	2,252	1,912	2,534
Net unrealized gains (losses) on commodity derivatives (net of tax of $(228), $(135) and $212, respectively)	755	231	(361)
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $(31), $154 and $4,067, respectively)	99	(516)	(6,938)
Other comprehensive income (loss), net of tax	7,027	681	(25,828)
Comprehensive income	279,689	191,957	56,803
Less: comprehensive income attributable to non-controlling interest	(14,220)	(14,242)	(9,661)
Comprehensive income available for common stock	$ 265,469	$ 177,715	$ 47,142

See Note 16 for additional disclosures related to Comprehensive Income.

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2018	As of December 31, 2017
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,776	$ 15,420
Restricted cash and equivalents	3,369	2,820
Accounts receivable, net	269,153	248,330
Materials, supplies and fuel	117,299	113,283
Derivative assets, current	1,500	304
Income tax receivable, net	12,978	—
Regulatory assets, current	48,776	81,016
Other current assets	29,982	25,367
Current assets held for sale	—	84,242
Total current assets	503,833	570,782
Investments	41,013	13,090
Property, plant and equipment	6,000,015	5,567,518
Less accumulated depreciation and depletion	(1,145,136)	(1,026,088)
Total property, plant and equipment, net	4,854,879	4,541,430
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	14,337	7,559
Regulatory assets, non-current	235,459	216,438
Other assets, non-current	14,352	10,149
Total other assets, non-current	1,563,602	1,533,600
TOTAL ASSETS	$ 6,963,327	$ 6,658,902

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of	
	December 31, 2018	December 31, 2017
	(in thousands, except share amounts)	
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 210,609	$ 160,887
Accrued liabilities	215,501	219,462
Derivative liabilities, current	947	2,081
Accrued income tax, net	—	1,022
Regulatory liabilities, current	29,810	6,832
Notes payable	185,620	211,300
Current maturities of long-term debt	5,743	5,743
Current liabilities held for sale	—	41,774
Total current liabilities	648,230	649,101
Long-term debt, net of current maturities	2,950,835	3,109,400
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	311,331	336,520
Regulatory liabilities, non-current	510,984	478,294
Benefit plan liabilities	145,147	159,646
Other deferred credits and other liabilities	109,377	105,735
Total deferred credits and other liabilities	1,076,839	1,080,195
Commitments and contingencies (See Notes 6, 7, 8, 9, 14, 18, 19, and 20)		
Equity:		
Stockholders' equity -		
Common stock $1 par value; 100,000,000 shares authorized; issued: 60,048,567 and 53,579,986, respectively	60,049	53,580
Additional paid-in capital	1,450,569	1,150,285
Retained earnings	700,396	548,617
Treasury stock at cost - 44,253 and 39,064, respectively	(2,510)	(2,306)
Accumulated other comprehensive income (loss)	(26,916)	(41,202)
Total stockholders' equity	2,181,588	1,708,974
Noncontrolling interest	105,835	111,232
Total equity	2,287,423	1,820,206
TOTAL LIABILITIES AND TOTAL EQUITY	$ 6,963,327	$ 6,658,902

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2018	December 31, 2017	December 31, 2016
	(in thousands)		
Operating activities:			
Net income	$ 272,662	$ 191,276	$ 82,631
Loss from discontinued operations, net of tax	6,887	17,099	64,162
Income (loss) from continuing operations	279,549	208,375	146,793
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	196,328	188,246	175,533
Deferred financing cost amortization	7,845	8,261	6,180
Stock compensation	12,390	7,626	10,885
Deferred income taxes	(24,239)	80,992	82,704
Employee benefit plans	14,068	10,141	14,291
Other adjustments, net	5,836	(4,773)	(5,519)
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(2,919)	(10,089)	1,211
Accounts receivable and other current assets	(45,966)	4,534	(27,172)
Accounts payable and other current liabilities	5,305	(28,222)	(33,023)
Regulatory assets	33,608	(15,407)	3,614
Regulatory liabilities	18,533	(4,536)	(14,082)
Contributions to defined benefit pension plans	(12,700)	(27,700)	(14,200)
Interest rate swap settlement	—	—	(28,820)
Other operating activities, net	6,689	(8,418)	(660)
Net cash provided by operating activities of continuing operations	494,327	409,030	317,735
Net cash provided by (used in) operating activities of discontinued operations	(5,516)	19,231	2,744
Net cash provided by operating activities	488,811	428,261	320,479
Investing activities:			
Property, plant and equipment additions	(457,524)	(326,010)	(454,952)
Acquisition of net assets, net of long-term debt assumed	—	—	(1,124,238)
Purchase of investment	(24,429)	—	—
Other investing activities	(4,281)	1,011	(562)
Net cash (used in) investing activities of continuing operations	(486,234)	(324,999)	(1,579,752)
Net cash provided by (used in) investing activities of discontinued operations	20,385	7,881	(8,413)
Net cash (used in) investing activities	(465,849)	(317,118)	(1,588,165)
Financing activities:			
Dividends paid on common stock	(106,591)	(96,744)	(87,570)
Common stock issued	300,834	4,408	121,619
Net increase (decrease) in commercial paper and short-term borrowings	(25,680)	114,700	19,800
Long-term debt - issuance	700,000	—	1,767,608
Long-term debt - repayments	(854,743)	(105,743)	(1,164,308)
Sale of noncontrolling interest	—	—	216,370
Distributions to noncontrolling interests	(19,617)	(18,397)	(9,561)
Other financing activities	(11,260)	(6,919)	(22,960)
Net cash provided by (used in) financing activities	(17,057)	(108,695)	840,998
Net change in cash, restricted cash and cash equivalents	5,905	2,448	(426,688)
Cash, restricted cash and cash equivalents beginning of year	18,240	15,792	442,480
Cash, restricted cash and cash equivalents end of year	$ 24,145	$ 18,240	$ 15,792

See Note 17 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
Balance at December 31, 2015	51,231,861	$ 51,232	39,720	$ (1,888)	$ 953,044	$ 472,534	$ (9,055)	$ —	$ 1,465,867
Net income (loss) available for common stock	—	—	—	—	—	72,970	—	9,661	82,631
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(25,828)	—	(25,828)
Dividends on common stock	—	—	—	—	—	(87,570)	—	—	(87,570)
Share-based compensation	145,634	146	(16,165)	668	4,665	—	—	—	5,479
Issuance of common stock	1,968,738	1,969	—	—	118,021	—	—	—	119,990
Issuance costs	—	—	—	—	(1,566)	—	—	—	(1,566)
Dividend reinvestment and stock purchase plan	51,234	50	—	—	2,933	—	—	—	2,983
Other stock transactions	—	—	(8,297)	429	47	—	—	—	476
Sale of noncontrolling interest	—	—	—	—	61,838	—	—	115,395	177,233
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(9,561)	(9,561)
Balance at December 31, 2016	53,397,467	$ 53,397	15,258	$ (791)	$1,138,982	$ 457,934	$(34,883)	$ 115,495	$ 1,730,134
Net income (loss) available for common stock	—	—	—	—	—	177,034	—	14,242	191,276
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	681	—	681
Reclassification of certain tax effects from AOCI	—	—	—	—	—	7,000	(7,000)	—	—
Dividends on common stock	—	—	—	—	—	(96,744)	—	—	(96,744)
Share-based compensation	134,266	134	23,806	(1,515)	8,948	—	—	—	7,567
Tax effect of share-based compensation	—	—	—	—	533	3,184	—	—	3,717
Issuance costs	—	—	—	—	(189)	—	—	—	(189)
Dividend reinvestment and stock purchase plan	48,253	49	—	—	3,107	—	—	—	3,156
Redemption of and distributions to noncontrolling interest	—	—	—	—	(1,096)	209	—	(18,505)	(19,392)
Balance at December 31, 2017	53,579,986	$ 53,580	39,064	$ (2,306)	$1,150,285	$ 548,617	$(41,202)	$ 111,232	$ 1,820,206
Net income (loss) available for common stock	—	—	—	—	—	258,442	—	14,220	272,662
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	7,027	—	7,027
Reclassification of certain tax effects from AOCI	—	—	—	—	—	—	740	—	740
Reclassification to regulatory asset	—	—	—	—	—	—	6,519	—	6,519
Dividends on common stock	—	—	—	—	—	(106,591)	—	—	(106,591)
Share-based compensation	92,830	93	5,189	(204)	7,301	—	—	—	7,190
Issuance of common stock	6,371,690	6,372	—	—	292,628	—	—	—	299,000
Issuance costs	—	—	—	—	(15)	—	—	—	(15)
Dividend reinvestment and stock purchase plan	4,061	4	—	—	216	—	—	—	220
Other stock transactions	—	—	—	—	154	(72)	—	—	82
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(19,617)	(19,617)
Balance at December 31, 2018	60,048,567	$ 60,049	44,253	$ (2,510)	$1,450,569	$ 700,396	$(26,916)	$ 105,835	$ 2,287,423

Dividends per share paid were $1.93, $1.81 and $1.68 for the years ended December 31, 2018, 2017 and 2016, respectively.

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

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, conducts our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation and Mining. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Segment Reporting

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

Our Electric Utilities segment includes the operating results of the regulated electric utility operations of South Dakota Electric, Wyoming Electric and Colorado Electric, which supply regulated electric utility services to areas in Colorado, Montana, South Dakota and Wyoming. Our Gas Utilities segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming.

All of our non-utility business segments support our Electric Utilities. Our Power Generation segment, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Wyoming and Colorado. Our Mining segment, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyoming. For further descriptions of our reportable business segments, see Note 5.

On November 1, 2017, our Board of Directors approved a complete divestiture of our Oil and Gas segment. We completed the divestiture of our Oil and Gas segment in 2018. The Oil and Gas segment assets and liabilities have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. At the time the assets were classified as held for sale, depreciation, depletion and amortization expenses were no longer recorded. Unless otherwise noted, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on discontinued operations, see Note 21.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain 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. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. For additional information on intercompany revenues, see Note 5.

Our Consolidated Statements of Income (Loss) include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our ownership interest in any jointly-owned electric utility generating facility, wind project or transmission tie. See Note 4 for additional information.

Variable Interest Entities

We evaluate arrangements and contracts with other entities to determine if they are VIEs and if we are the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

Our evaluation of whether our interest qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement. Black Hills Colorado IPP is a VIE. See additional information in Note 12.

Cash and Cash Equivalents and Restricted Cash

We consider all highly liquid investments with an original maturity of three months or less to be cash and cash equivalents. We maintain cash accounts for various specified purposes, which are classified as restricted cash. For purposes of the cash flow statements, we consider all highly liquid investments with original maturities of three months or less at the time of purchase to be cash and cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Electric and Gas Utilities business segments primarily consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and estimated unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Mining and Power Generation business segments consists of amounts due from sales of coal, electric energy and capacity.

We maintain an allowance for doubtful accounts which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Following is a summary of accounts receivable as of December 31 (in thousands):

2018	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,721	$ 35,125	$ (448)	$ 74,398
Gas Utilities	96,123	90,521	(2,592)	184,052
Power Generation	1,876	—	—	1,876
Mining	3,988	—	—	3,988
Corporate	5,008	—	(169)	4,839
Total	$ 146,716	$ 125,646	$ (3,209)	$ 269,153

2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,347	$ 36,384	$ (586)	$ 75,145
Gas Utilities	81,256	88,967	(2,495)	167,728
Power Generation	1,196	—	—	1,196
Mining	2,804	—	—	2,804
Corporate	1,457	—	—	1,457
Total	$ 126,060	$ 125,351	$ (3,081)	$ 248,330

Changes to allowance for doubtful accounts for the years ended December 31, were as follows (in thousands):

	Balance at Beginning of Year	Adjustments [a]	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
2018	$ 3,081	$ —	$ 6,859	$ 4,092	$ (10,823)	$ 3,209
2017	$ 2,392	$ —	$ 4,926	$ 8,262	$ (12,499)	$ 3,081
2016	$ 1,741	$ 2,158	$ 2,704	$ 4,915	$ (9,126)	$ 2,392

(a) Represents allowance balances added with the SourceGas acquisition.

Revenue Recognition

Revenue is recognized in an amount that reflects the consideration we expect to receive in exchange for goods or services, when control of the promised goods or services is transferred to our customers. Our primary types of revenue contracts are:

- Regulated natural gas and electric utility services tariffs - Our utilities have regulated operations, as defined by ASC 980, that provide services to regulated customers under rates, charges, terms and conditions of service, and prices determined by the jurisdictional regulators designated for our service territories. Collectively, these rates, charges, terms and conditions are included in a tariff, which governs all aspects of the provision of our regulated services. Our regulated services primarily encompass single performance obligations material to the context of the contract for delivery of either commodity natural gas, commodity electricity, natural gas transportation or electric transmission services. These service revenues are variable based on quantities delivered, influenced by seasonal business and weather patterns. Tariffs are only permitted to be changed through a rate-setting process involving the regulator-empowered statute to establish contractual rates between the utility and its customers. All of our utilities' regulated sales are subject to regulatory-approved tariffs.

- Power sales agreements - Our Electric Utilities and Power Generation segments have long-term wholesale power sales agreements with other load-serving entities, including affiliates, for the sale of excess power from owned generating units. These agreements include a combination of "take or pay" arrangements, where the customer is obligated to pay for the energy regardless of whether it actually takes delivery, as well as "requirements only" arrangements, where the customer is only obligated to pay for the energy the customer needs. In addition to these long-term contracts, Black

Hills also sells excess energy to other load-serving entities on a short-term basis. The pricing for all of these arrangements is included in the executed contracts or confirmations, reflecting the standalone selling price and is variable based on energy delivered.

- Coal supply agreements - Our Mining segment sells coal primarily under long-term contracts to utilities for use at their power generating plants, including affiliate electric utilities, and an affiliate non-regulated power generation entity. The contracts include a single promise to supply coal necessary to fuel the customers' facilities during the contract term. The transaction price is established in the coal supply agreements, including cost-based agreements with the affiliated regulated utilities, and is variable based on tons of coal delivered.

- Other non-regulated services - Our Gas and Electric Utilities segments also provide non-regulated services primarily comprised of appliance repair service and protection plans, electric and natural gas technical infrastructure construction and maintenance services, and in Nebraska and Wyoming, an unbundled natural gas commodity offering under the regulatory-approved Choice Gas Program. Revenue contracts for these services generally represent a single performance obligation with the price reflecting the standalone selling price stated in the agreement, and the revenue is variable based on the units delivered or services provided.

The following tables depict the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition for each of the reporting segments, for the year ended December 31, 2018. Sales tax and other similar taxes are excluded from revenues.

Year ended December 31, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:			(in thousands)			
Retail	$ 594,329	$ 833,379	$ —	$ 65,803	$ (32,194)	$ 1,461,317
Transportation	—	140,705	—	—	(1,348)	139,357
Wholesale	33,687	—	52,396	—	(46,562)	39,521
Market - off-system sales	24,799	866	—	—	(8,102)	17,563
Transmission/Other	56,209	49,402	—	—	(14,827)	90,784
Revenue from contracts with customers	709,024	1,024,352	52,396	65,803	(103,033)	1,748,542
Other revenues	2,427	955	36,556	2,230	(36,442)	5,726
Total revenues	$ 711,451	$ 1,025,307	$ 88,952	$ 68,033	$ (139,475)	$ 1,754,268
Timing of revenue recognition:						
Services transferred at a point in time	$ —	$ —	$ —	$ 65,803	$ (32,194)	$ 33,609
Services transferred over time	709,024	1,024,352	52,396	—	(70,839)	1,714,933
Revenue from contracts with customers	$ 709,024	$ 1,024,352	$ 52,396	$ 65,803	$ (103,033)	$ 1,748,542

The majority of our revenue contracts are based on variable quantities delivered; any fixed consideration contracts with an expected duration of one year or more are immaterial to our consolidated revenues. Variable consideration constraints in the form of discounts, rebates, credits, price concessions, incentives, performance bonuses, penalties or other similar items are not material for our revenue contracts. We are the principal in our revenue contracts, as we have control over the services prior to those services being transferred to the customer.

Revenue Not in Scope of ASC 606

Other revenues included in the table above include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 840, derivative revenue under ASC 815 and alternative revenue programs revenue under ASC 980. The majority of our lease revenue is related to a 20-year power sale agreement between Black Hills Colorado IPP and affiliate Colorado Electric. This agreement is accounted for as a direct financing lease whereby Black Hills Colorado IPP receives revenue for energy delivered and related capacity payments. This lease revenue is eliminated in our consolidated revenues.

Significant Judgments and Estimates

TCJA Revenue Reserve

The TCJA or "tax reform" signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21% effective for tax years beginning after December 31, 2017. Black Hills has been collaborating with utility commissions in the states in which it provides utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We have received state utility commission approvals to provide the benefits of federal tax reform to utility customers in six states. We estimated and recorded a reserve to revenue of approximately $37 million during the year ended December 31, 2018. As of December 31, 2018, $19 million has been returned to customers and approximately $18 million remains in reserve as a current regulatory liability.

Unbilled Revenue

To the extent that deliveries have occurred but a bill has not been issued, our utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable further discussed above. We do not typically incur costs that would be capitalized to obtain or fulfill a contract.

Practical Expedients

Our revenue contracts generally provide for performance obligations that are fulfilled and transfer control to customers over time, represent a series of distinct services that are substantially the same, involve the same pattern of transfer to the customer, and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice.

We have revenue contract performance obligations with similar characteristics, and we reasonably expect that the financial statement impact of applying the new revenue recognition guidance to a portfolio of contracts would not differ materially from applying this guidance to the individual contracts or performance obligations within the portfolio. Therefore, we have elected the portfolio approach in applying the new revenue guidance.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2018	2017
Materials and supplies	$ 75,081	$ 69,732
Fuel - Electric Utilities	2,850	2,962
Natural gas in storage	39,368	40,589
Total materials, supplies and fuel	$ 117,299	$ 113,283

Materials and supplies represent parts and supplies for all of our business segments. Fuel - Electric Utilities represents oil, gas and coal on hand used to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are recorded using the weighted-average cost method and are valued at the lower-of-cost or net realizable value. The value of our Natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

Investments

We account for investments that we do not control under the cost method of accounting as we do not have the ability to exercise significant influence over the operating and financial policies of the investee. The cost method investments are recorded at cost and we record dividend income when applicable dividends are declared.

In February 2018, we contributed $28 million of assets in exchange for equity securities in a privately held company. The carrying value of our investment in the equity securities was determined using the cost method. We review this investment on a periodic basis to determine whether a significant event or change in circumstances has occurred that may have an adverse effect on the value of the investment. We estimate that the fair value of this cost method investment approximated or exceeded its carrying value as of December 31, 2018.

The following table presents the carrying value of our investments (in thousands) as of December 31:

	2018	2017
Cost method investment	$ 28,201	$ —
Cash surrender value of life insurance contracts	12,812	13,090
Total investments	$ 41,013	$ 13,090

Accrued Liabilities

The following amounts by major classification are included in Accrued liabilities on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2018	2017
Accrued employee compensation, benefits and withholdings	$ 63,742	$ 52,467
Accrued property taxes	42,510	42,029
Customer deposits and prepayments	43,574	44,420
Accrued interest	31,759	33,822
CIAC current portion	1,485	1,552
Other (none of which is individually significant)	32,431	45,172
Total accrued liabilities	$ 215,501	$ 219,462

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets. We also classify our base or "cushion gas" as property, plant and equipment. Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. Estimated removal costs associated with non-legal retirement obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, result in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, depreciation is computed on a unit-of-production methodology based on plant hours run.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized, but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life continue to be amortized over their estimated useful lives.

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Our annual goodwill impairment testing date is as of October 1, which aligns our testing date with our financial planning process.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. See Note 5 for additional business segment information.

Our goodwill impairment analysis includes an income approach and a market approach to estimate the fair value of our reporting units. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital, long-term earnings and merger multiples for comparable companies.

We believe that the goodwill reflects the inherent value of the relatively stable, long-lived cash flows of the regulated electric and gas utility businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our utilities. Goodwill balances were as follows (in thousands):

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at December 31, 2016	$ 248,479	$ 1,042,210	$ 8,765	$ 1,299,454
Additions	—	—	—	—
Ending balance at December 31, 2017	$ 248,479	$ 1,042,210	$ 8,765	$ 1,299,454
Additions	—	—	—	—
Ending balance at December 31, 2018	$ 248,479	$ 1,042,210	$ 8,765	$ 1,299,454

Our intangible assets represent easements, rights-of-way, customer listings and trademarks. The finite-lived intangible assets are amortized using a straight-line method based on estimated useful lives; these assets are currently being amortized from 2 years to 40 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

	2018	2017	2016
Intangible assets, net, beginning balance	$ 7,559	$ 8,392	$ 3,380
Additions [(a)]	7,602	—	5,522
Amortization expense [(b)]	(824)	(833)	(510)
Intangible assets, net, ending balance	$ 14,337	$ 7,559	$ 8,392

(a) The 2018 addition is related to the Busch Ranch 1 Wind Farm contract intangible asset. See Note 4 for further information.
(b) Amortization expense for existing intangible assets is expected to be $0.8 million for each year of the next five years.

Asset Retirement Obligations

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income (Loss). The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations. For oil and gas liabilities classified as held for sale, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and prior to held-for-sale classification were depleted pursuant to the use of the full cost method of accounting. Additional information is included in Note 8 and 21.

Fair Value Measurements

Financial Instruments

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

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

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

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

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

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs. We currently do not have any Level 3 investments.

Valuation Methodologies for Derivatives

The commodity contracts for the Electric and Gas Utilities, valued using the market approach, include exchange-traded futures, options, basis swaps and over-the-counter swaps (Level 2) for natural gas contracts. For exchange-traded futures, options and basis swap Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For over-the-counter swaps and options Level 2 assets and liabilities, fair value was derived from, or corroborated by, observable market pricing data. In addition, the fair value for the over-the-counter swaps and option derivatives, if material, include a CVA component. The CVA considers the fair value of the derivative and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Additional information on fair value measurements is included in Notes 10, 11 and 18 .

Derivatives and Hedging Activities

All our derivatives are measured at fair value and recognized as either assets or liabilities on the Consolidated Balance Sheets, except for derivative contracts that qualify for and are elected under the normal purchase and normal sales exception. 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 amount of time, and price is not tied to an unrelated underlying derivative. Normal purchase and sales contracts are recognized when the underlying physical transaction is completed under the accrual basis of accounting. As part of our Electric and Gas Utility operations, we enter into contracts to buy and sell energy to meet the requirements of our customers.

In addition, certain derivatives contracts approved by regulatory authorities are either recovered or refunded through customer rates. Any changes in the fair value of these approved derivative contracts are deferred as a regulatory asset or regulatory liability pursuant to ASC 980.

We also have some derivatives that qualify for hedge accounting and are designated as cash flow hedges. The effective portion of the derivative gain or loss is deferred in AOCI and reclassified into earnings when the corresponding hedged transaction is recognized in earnings. Changes in the fair value of all other derivatives contracts are recognized in earnings.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty. We reflect the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterpart when a legal right of offset exists.

Deferred Financing Costs

Deferred financing costs are amortized over the estimated useful life of the related debt. Deferred financing costs are presented on the balance sheet as an adjustment to the related debt liabilities.

Regulatory Accounting

Our Electric Utilities and Gas Utilities follow accounting standards for regulated operations and reflect the effects of the numerous rate-making principles followed by the various state and federal agencies regulating the utilities. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which could require these net regulatory assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities as of December 31 (in thousands):

	2018	2017
Regulatory assets		
Deferred energy and fuel cost adjustments - current [(a)]	$ 29,661	$ 20,187
Deferred gas cost adjustments [(a)]	3,362	31,844
Gas price derivatives [(a)]	6,201	11,935
Deferred taxes on AFUDC [(b)]	7,841	7,847
Employee benefit plans [(c)]	110,524	109,235
Environmental [(a)]	959	1,031
Asset retirement obligations [(a)]	529	517
Loss on reacquired debt [(a)]	21,001	20,667
Renewable energy standard adjustment [(a)]	1,722	1,088
Deferred taxes on flow through accounting [(c)]	31,044	26,978
Decommissioning costs	11,700	13,287
Gas supply contract termination [(a)]	14,310	20,001
Other regulatory assets [(a)]	45,381	32,837
Total regulatory assets	284,235	297,454
Less current regulatory assets	(48,776)	(81,016)
Regulatory assets, non-current	$ 235,459	$ 216,438
Regulatory liabilities		
Deferred energy and gas costs [(a)]	$ 6,991	$ 3,427
Employee benefit plan costs and related deferred taxes [(c)]	42,533	40,629
Cost of removal [(a)]	150,123	130,932
Excess deferred income taxes [(c)]	310,562	301,553
TCJA revenue reserve	18,032	—
Other regulatory liabilities [(c)]	12,553	8,585
Total regulatory liabilities	540,794	485,126
Less current regulatory liabilities	(29,810)	(6,832)
Regulatory liabilities, non-current	$ 510,984	$ 478,294

(a) Recovery of costs, but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Deferred Energy and Fuel Cost Adjustments - Current - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our Electric Utility customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission. Our Electric Utilities file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions. The recovery period for these costs is less than a year.

Deferred Gas Cost Adjustment - Our regulated gas utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state utility commissions. The recovery period for these costs is less than a year.

Gas Price Derivatives - Our regulated utilities, as allowed or required by state utility commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. Gas price derivatives at December 31, 2018 are hedged over a maximum forward term of 2 years.

Deferred Taxes on AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plan and post-retirement benefit plans in regulatory assets rather than in AOCI, including costs being amortized from the Aquila and SourceGas Transactions.

Environmental - Environmental expenditures are costs associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 8 for additional details.

Loss on Reacquired Debt - Loss on reacquired debt is recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered currently deductible for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - South Dakota Electric and Colorado Electric received approval in 2014 for recovery of the remaining net book values and decommissioning costs of their decommissioned coal plants. In 2018, Arkansas Gas received approval to record decommissioning costs in a regulatory asset, with recovery to be determined in a future regulatory filing.

Gas Supply Contract Termination - Black Hills Gas Holdings had agreements under the previous ownership that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. The majority of these purchases were committed to distribution customers in Nebraska, Colorado, and Wyoming, which are subject to cost recovery mechanisms. The prices to be paid under these agreements varied, ranging from $6 to $8 per MMBtu at the time of acquisition, which exceeded market prices. We recorded a liability for this contract in our purchase price allocation. We were granted approval to terminate these agreements from the NPSC, CPUC and WPSC, on the basis that these agreements were not beneficial to customers over the long term. We received written orders allowing us to create a regulatory asset for the net buyout costs associated with the contract termination, and recover the majority of costs from customers over a period of five years. We terminated the contract and settled the liability on April 29, 2016.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Deferred Energy and Gas Costs **-** Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

Employee Benefit Plan Costs and Related Deferred Taxes **-** Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Cost of Removal **-** Cost of removal represents the estimated cumulative net provisions for future removal costs for which there is no legal obligation for removal included in depreciation expense.

Excess Deferred Income Taxes - The revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the TCJA was recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA.

Revenue Subject to Refund - Revenue subject to refund at December 31, 2018 represent revenue reserved as a result of the TCJA. See above "*TCJA Revenue Reserve"* under Revenue recognition for further disclosure.

See Note 13 for additional information on regulatory matters.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain subsidiaries acquired file as a separate consolidated group. Where applicable, each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating expense adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. See Notes 13 and 15 for additional information.

It is our policy to apply the flow-through method of accounting for investment tax credits. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. An exception to this general policy is the deferral method, which applies to our regulated businesses. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax (expense) benefit on the Consolidated Statements of Income (Loss).

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 15 for additional information.

Earnings per Share of Common Stock

Basic earnings per share from continuing and discontinued operations is computed by dividing Net income (loss) from continuing and discontinued operations by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to equity units, outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings (loss) per share is as follows for the years ended December 31 (in thousands):

	2018	2017	2016
Net income (loss) available for common stock	$ 258,442	$ 177,034	$ 72,970
Weighted average shares - basic	54,420	53,221	51,922
Dilutive effect of:			
Equity Units	898	1,783	1,222
Equity compensation	168	116	127
Weighted average shares - diluted	55,486	55,120	53,271
Net income (loss) available for common stock, per share - Diluted	$ 4.66	$ 3.21	$ 1.37

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive for the years ended December 31 (in thousands):

	2018	2017	2016
Equity compensation	16	11	3
Anti-dilutive shares excluded from computation of earnings (loss) per share	16	11	3

Business Combinations

We record acquisitions in accordance with ASC 805, *Business Combinations,* with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, *Business Combinations* requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 for additional detail on the accounting for the SourceGas Acquisition.

Noncontrolling Interests

We account for changes in our controlling interests of subsidiaries according to ASC 810*, Consolidations.* ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the noncontrolling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional detail on Noncontrolling Interests.

Share-Based Compensation

We account for our share-based compensation arrangements in accordance with ASC 718, *Compensation-Stock Compensation*, 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. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures.

Recently Issued Accounting Standards

Leases, ASU 2016-02

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which supersedes ASC 840, Leases. This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for most leases, whereas today only financing-type lease liabilities (capital leases) are recognized on the balance sheet. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement, which may result in changes to the classification of an arrangement as a lease. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. The ASU expands the disclosure requirements of lease arrangements. Under the original guidance, lessees and lessors will use a modified retrospective transition approach, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. The guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard. The FASB also issued additional amendments to the new lease standard in July 2018, ASU No. 2018-11, allowing companies to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported.

We adopted this standard on January 1, 2019. For existing or expired land easements that were not previously accounted for as a lease, we elected the practical expedient which provides for no assessment of these easements. Further, we adopted the new standard with a cumulative effect adjustment with prior year comparative financial information remaining as previously reported when transitioning to the new standard. The standard also provides a transition practical expedient, commonly referred to as the "package of three", that must be taken together and allows entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. We elected the "package of three" practical expedient. We have implemented a new lease accounting system and adjusted related procedures and controls accordingly. On January 1, 2019, we will record an operating lease right of use asset and an off-setting operating lease obligation liability of approximately $3.2 million. Adoption of this standard did not have a material impact on our financial position, results of operations or cash flows.

Derivatives and Hedging: Targeted Improvement to Accounting for Hedging Activities, 2017-12

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvement to Accounting for Hedging Activities.* This standard better aligns risk management activities and financial reporting for hedging relationships, simplifies hedge accounting requirements and improves disclosures of hedging arrangements. This ASU is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We have adopted this standard on January 1, 2019. Adoption of this standard did not have a material impact on our financial position, results of operations or cash flows.

Simplifying the Test for Goodwill Impairment, 2017-04

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment* by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, applied on a prospective basis with early adoption permitted. We do not anticipate the adoption of this guidance to have any impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Revenue from Contracts with Customers, ASU 2014-09

Effective January 1, 2018, we adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, and its related amendments (collectively known as ASC 606). Under this standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. We applied the five-step method outlined in the ASU to all in-scope revenue streams and elected the modified retrospective implementation method. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows. Implementation of the standard did not have a significant impact on the measurement or recognition of revenue; therefore, no cumulative adoption adjustment to the opening balance of Retained earnings at the date of initial application was necessary. The additional disclosures required by the ASU are included in Note 1.

Compensation - Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost, ASU 2017-07

Effective January 1, 2018, we adopted ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost*. The standard requires employers to report the service cost component in the same line item(s) as other compensation costs, and requires the other components of net periodic pension and post-retirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component may be eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. The capitalization of only the service cost component of net periodic pension and post-retirement benefit costs in assets was applied on a prospective basis for the year ended December 31, 2018. Retrospective impact was not material and therefore prior year presentation was not changed. For our rate-regulated entities, we capitalize the other components of net periodic benefit costs into regulatory assets or regulatory liabilities and maintain a FERC-to-GAAP reporting difference for these capitalized costs. The presentation changes required for net periodic pension and post-retirement costs resulted in offsetting changes to Operating income and Other income. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, ASU 2016-15

Effective January 1, 2018, we adopted ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force).* This ASU requires changes in the presentation of certain items, including but not limited to, debt prepayment or debt extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. We implemented this standard effective January 1, 2018 using the retrospective transition method. This standard had no impact on our financial position, results of operations or cash flows.

Statement of Cash Flows: Restricted Cash, ASU 2016-18

Effective January 1, 2018, we adopted ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash.* This ASU provides guidance on the presentation of restricted cash or restricted cash equivalents and reduces the diversity in practice. This ASU requires amounts generally described as restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling beginning-of-period and end-of-period total amounts on the statement of cash flows. We elected, as permitted by the standard, to early adopt ASU 2016-18 retrospectively as of January 1, 2017 and have applied it to all periods presented herein. The adoption of ASU 2016-18 did not have a material impact to our condensed consolidated financial statements. The effect of the adoption of ASU 2016-18 on our Condensed Consolidated Statements of Cash Flows was to include restricted cash balances in the beginning and end of period balances of cash, cash equivalents, and restricted cash. The change in restricted cash was previously disclosed in investing activities in the Condensed Consolidated Statements of Cash Flows.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, ASU 2018-02

In February 2018, the FASB issued ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* This ASU was issued to address industry concerns regarding the application of current accounting guidance to certain provisions of the new tax reform legislation. This ASU permits entities to make a one-time reclassification from AOCI to retained earnings for stranded tax effects resulting from the newly enacted corporate tax rate. The amount of the reclassification is calculated on the basis of the difference between the historical and newly enacted tax rates for deferred tax liabilities and assets related to items within AOCI. The ASU is effective for fiscal years beginning after December 15, 2018, including interim periods therein, and early adoption is permitted. We have implemented this ASU effective December 22, 2017, the enactment date of the TCJA, which resulted in a reclassification of $7.0 million of stranded tax effects from AOCI to retained earnings. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or cash flows.

Improvements to Employee Share-Based Payment Accounting, ASU 2016-09

In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting*. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We implemented this ASU effective January 1, 2017, recording a cumulative-effect adjustment of $3.2 million to Retained earnings in the Consolidated Balance Sheets as of the date of adoption, representing previously recorded forfeitures and excess tax benefits generated in years prior to 2017 that were previously not recognized in stockholders' equity due to NOLs in those years. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or cash flows.

(2) ACQUISITION

Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, including the assumption of $760 million in debt at closing. SourceGas is a 100% owned subsidiary of Black Hills Utility Holdings, Inc., a wholly-owned subsidiary of Black Hills Corporation and has been renamed Black Hills Gas Holdings, LLC. Black Hills Gas Holdings primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado.

Cash consideration of $1.135 billion paid on February 12, 2016 to close the SourceGas Acquisition included net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.325 million shares of our common stock, 5.98 million Equity Units, and $546 million in net proceeds from our debt offerings on January 13, 2016. We funded the cash consideration and out-of-pocket expenses payable with the SourceGas Acquisition using the proceeds listed above, cash on hand, and draws under our revolving credit facility.

In connection with the acquisition, the Company recorded pre-tax, incremental acquisition costs of approximately $45 million for the year ending December 31, 2016. These costs consisted of transaction costs, professional fees, employee-related expenses and other miscellaneous costs. The costs are recorded primarily in Other operating expenses on the Consolidated Statements of Income.

Our consolidated operating results for the year ended December 31, 2016 include revenues of $348 million and net income of $15 million, attributable to SourceGas for the period from February 12 through December 31, 2016. The SourceGas operating results are reported in our Gas Utilities segment. We believe the SourceGas Acquisition enhances Black Hills Corporation's utility growth strategy, providing greater operating scale, driving more efficient delivery of services and benefiting customers.

We accounted for the SourceGas Acquisition in accordance with ASC 805, *Business Combinations,* with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. Substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

The final purchase price allocation of the fair value of the assets acquired and liabilities assumed is included in the table below. The cash consideration paid of $1.124 billion, net of long-term debt assumed of $760 million and a working capital adjustment received of approximately $11 million, resulted in goodwill of $940 million. We had up to one year from the acquisition date to finalize the purchase price allocation. The working capital adjustment received in 2016 of $11 million reflected changes in valuation estimates for intangible assets, accrued liabilities and deferred taxes. Approximately $252 million of the goodwill balance is amortizable for tax purposes, relating to the partnership interests that were directly acquired in the transaction. The remainder of the goodwill balance is not amortizable for tax purposes. Goodwill generated from the acquisition reflects the benefits of increased operating scale and organic growth opportunities.

	(in thousands)
Purchase Price	$ 1,894,882
Less: Long-term debt assumed	(760,000)
Less: Working capital adjustment received	(10,644)
Consideration paid, net of working capital adjustment received	$ 1,124,238
Allocation of Purchase Price:	
Current Assets	$ 112,983
Property, plant & equipment, net	1,058,093
Goodwill	939,695
Deferred charges and other assets, excluding goodwill	133,299
Current liabilities	(172,454)
Long-term debt	(758,874)
Deferred credits and other liabilities	(188,504)
Total consideration paid, net of working-capital adjustment received	$ 1,124,238

Conditions of SourceGas Acquisition Regulatory Approval

The acquisition was subject to regulatory approvals from the public utility commissions in Arkansas (APSC), Colorado (CPUC), Nebraska (NPSC), and Wyoming (WPSC). Approvals were obtained from all commissions, subject to various conditions. We have met all conditions as set forth in the commissions' approval orders.

Pro Forma Results (unaudited)

We calculated the pro forma impact of the SourceGas Acquisition and the associated debt and equity financings on our operating results for the year ended December 31, 2016. The following pro forma results give effect to the acquisition, assuming the transaction closed on January 1, 2016:

	Pro Forma Results December 31, 2016 (in thousands, except per share amounts)
Revenue	$ 1,617,878
Income from continuing operations	$ 177,040
Net income (loss)	$ 112,878
Earnings from continuing operations per share, Basic	$ 3.41
Earnings from continuing operations per share, Diluted	$ 3.32

We derived the pro forma results for the SourceGas Acquisition based on historical financial information obtained from the sellers and certain management assumptions. Our pro forma adjustments relate to incremental interest expense associated with the financings to effect the transaction, and for the year ended December 31, 2016, also include adjustments to shares outstanding to reflect the equity issuances as if they had occurred on January 1, 2016, and to reflect pro forma dilutive effects of the equity units issued. The pro forma results do not reflect any cost savings, (or associated costs to achieve such savings) from operating efficiencies or restructuring that could result from the acquisition, and exclude any unique one-time items resulting from the acquisition that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the year ended December 31, 2016 reflect unfavorable weather impacts resulting in lower gas usage by our customers than in the same periods of the prior year. In addition, we calculated the tax impact of these adjustments at an estimated combined federal and state income tax rate of 37%.

These pro forma results are for illustrative purposes only and do not purport to be indicative of the results that would have been obtained had the SourceGas Acquisition been completed on January 1, 2016, or that may be obtained in the future.

Seller's noncontrolling interest

As part of the SourceGas Transaction, a seller retained a 0.5% noncontrolling interest and we entered into an associated option agreement with the holder for the 0.5% retained interest. In March 2017, we exercised our call option and purchased the remaining 0.5% equity interest in SourceGas for $5.6 million.

(3) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

	2018		2017		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$ 1,318,643	41	$ 1,315,044	39	32	46
Electric transmission	437,082	51	407,203	51	48	53
Electric distribution	793,725	48	755,213	48	45	50
Plant acquisition adjustment [(a)]	4,870	32	4,870	32	32	32
General	233,531	28	232,842	31	26	28
Capital lease - plant in service [(b)]	261,441	20	261,441	20	20	20
Total electric plant in service	3,049,292		2,976,613			
Construction work in progress	60,480		13,595			
Total electric plant	3,109,772		2,990,208			
Less accumulated depreciation and amortization	706,869		644,022			
Electric plant net of accumulated depreciation and amortization	$ 2,402,903		$ 2,346,186			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 12 years remaining.
(b) Capital lease - plant in service represents the assets accounted for as a capital lease under the PPA between Colorado Electric and Black Hills Colorado IPP. The capital lease ends in conjunction with the expiration of the PPA on December 31, 2031.

Gas Utilities	2018 Property, Plant and Equipment	2018 Weighted Average Useful Life (in years)	2017 Property, Plant and Equipment	2017 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Gas plant:						
Production	$ 13,580	35	$ 10,495	35	24	71
Gas transmission	423,873	48	366,433	48	22	66
Gas distribution	1,595,644	42	1,413,431	42	33	47
Cushion gas - depreciable [(a)]	3,539	28	3,539	28	28	28
Cushion gas - not depreciated [(a)]	46,369	N/A	47,466	N/A	N/A	N/A
Storage	29,335	30	28,520	31	28	38
General	355,920	19	336,869	19	10	24
Total gas plant in service	2,468,260		2,206,753			
Construction work in progress	38,271		44,440			
Total gas plant	2,506,531		2,251,193			
Less accumulated depreciation and amortization	279,580		229,170			
Gas plant net of accumulated depreciation and amortization	$ 2,226,951		$ 2,022,023			

(a) Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability. Depreciation of cushion gas is determined by the respective regulatory jurisdiction in which the cushion gas resides.

2018	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years) Minimum	Lives (in years) Maximum
Power Generation	$ 173,997	$ 11,796	$ 185,793	$ 64,273	$ 121,520	31	2	40
Mining	$ 175,650	$ —	$ 175,650	$ 111,689	$ 63,961	13	2	59

2017	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years) Minimum	Lives (in years) Maximum
Power Generation	$ 155,569	$ 224	$ 155,793	$ 57,813	$ 97,980	33	2	40
Mining	$ 158,370	$ —	$ 158,370	$ 108,844	$ 49,526	14	2	59

	2018						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Add Accumulated Depreciation - Capital Lease Elimination [(a)]	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$ 5,721	$ 16,548	$ 22,269	$ 670	$ 17,945	$ 39,544	8	3	30

(a) Reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP of $18 million.

	2017						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Add Accumulated Depreciation - Capital Lease Elimination [(a)]	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$ 5,580	$ 6,374	$ 11,954	$ 309	$ 14,070	$ 25,715	8	3	30

(a) Reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP of $14 million.

(4) JOINTLY OWNED FACILITIES

Our consolidated financial statements include our share of several jointly-owned utility and non-regulated facilities as described below. Our share of the facilities' expenses are reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income (Loss). Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- South Dakota Electric owns a 20% interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. South Dakota Electric receives its proportionate share of the Wyodak Plant's capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying South Dakota Electric with coal for its share of the Wyodak Plant, our Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Wyodak Plant under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.

- South Dakota Electric also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the SPP region. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West. South Dakota Electric is committed to pay its proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

- South Dakota Electric owns 52% of the Wygen III coal-fired generation facility. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. South Dakota Electric retains responsibility for plant operations. Our Mining subsidiary supplies coal to Wygen III for the life of the plant.

- Black Hills Wyoming owns 76.5% of the Wygen I plant while MEAN owns the remaining ownership percentage. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our Mining subsidiary during the life of the facility. Black Hills Wyoming retains responsibility for plant operations.

At December 31, 2018, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 115,198	$ 384	$ 61,730
Transmission Tie	$ 20,855	$ 1,860	$ 6,667
Wygen I	$ 119,273	$ 498	$ 44,155
Wygen III	$ 140,072	$ 645	$ 22,647

Jointly Owned facility - Related Party

Colorado Electric owns 50% of the Busch Ranch I Wind Farm while Black Hills Electric Generation owns the remaining 50% ownership interest. Each company is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm over the life of the facility. On December 11, 2018, Black Hills Electric Generation purchased its 50% ownership interest in the 29 MW Busch Ranch I Wind Farm from AltaGas for $16 million. Colorado Electric retains responsibility for operations of the wind farm. We recorded this purchase as an asset acquisition at fair value with $8.7 million of the purchase price recorded as wind generation assets, and $7.6 million recorded as an intangible asset, reflective of the fair value of the PPA. Black Hills Electric Generation will provide its share of energy from the wind farm to Colorado Electric through a new PPA, which replaces the PPA Colorado Electric had with AltaGas, expiring in October 2037.

(5) BUSINESS SEGMENT INFORMATION

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

Segment information was as follows (in thousands):

Total Assets (net of intercompany eliminations) as of December 31,	2018	2017
Electric [(a)]	$ 2,895,577	$ 2,906,275
Gas	3,623,475	3,426,466
Power Generation [(a)]	154,203	60,852
Mining	80,594	65,455
Corporate and Other	209,478	115,612
Discontinued operations [(b)]	—	84,242
Total assets	$ 6,963,327	$ 6,658,902

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.
(b) On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. See Note 21 for additional information.

Capital Expenditures [(a)] for the years ended December 31,	2018	2017
Capital expenditures		
Electric Utilities	$ 152,524	$ 138,060
Gas Utilities	288,438	184,389
Power Generation	30,945	1,864
Mining	18,794	6,708
Corporate and Other	11,723	6,668
Total capital expenditures of continuing operations	502,424	337,689
Total capital expenditures of discontinued operations	2,402	23,222
Total capital expenditures	$ 504,826	$ 360,911

(a) Includes accruals for property, plant and equipment.

Property, Plant and Equipment as of December 31,	2018	2017
Electric Utilities [a]	$ 3,109,772	$ 2,990,208
Gas Utilities	2,506,531	2,251,193
Power Generation [a]	185,793	155,793
Mining	175,650	158,370
Corporate and Other	22,269	11,954
Total property, plant and equipment	$ 6,000,015	$ 5,567,518

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

Consolidating Income Statement

Year ended December 31, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue -								
Contracts with customers	$ 686,272	$1,022,828	$ 5,833	$ 33,609	$ —	$ —	$ —	$1,748,542
Other revenues	2,427	955	1,413	931	—	—	—	5,726
	688,699	1,023,783	7,246	34,540	—	—	—	1,754,268
Inter-company operating revenue -								
Contracts with customers	22,752	1,524	46,563	32,194	148	(103,181)	—	—
Other revenues	—	—	35,143	1,299	379,775	(416,217)	—	—
	22,752	1,524	81,706	33,493	379,923	(519,398)	—	—
Total revenue	711,451	1,025,307	88,952	68,033	379,923	(519,398)	—	1,754,268
Fuel, purchased power and cost of natural gas sold	277,093	462,153	—	—	43	(113,679)	—	625,610
Operations and maintenance	186,175	291,481	33,727	43,728	324,917	(344,735)	—	535,293
Depreciation, depletion and amortization	98,639	86,434	6,913	7,965	21,161	(24,784)	—	196,328
Operating income (loss)	149,544	185,239	48,312	16,340	33,802	(36,200)	—	397,037
Interest expense	(55,660)	(85,760)	(5,178)	(538)	(150,455)	155,975	—	(141,616)
Interest income	2,993	5,580	183	2	113,188	(120,305)	—	1,641
Other income (expense), net	(1,235)	(431)	(53)	164	456,481	(456,106)	—	(1,180)
Income tax benefit (expense) [a]	(16,702)	55,655	(8,267)	(3,069)	(3,804)	(146)	—	23,667
Income (loss) from continuing operations	78,940	160,283	34,997	12,899	449,212	(456,782)	—	279,549
(Loss) from discontinued operations, net of tax	—	—	—	—	—	—	(6,887)	(6,887)
Net income (loss)	78,940	160,283	34,997	12,899	449,212	(456,782)	(6,887)	272,662
Net income attributable to noncontrolling interest	—	—	(14,220)	—	—	—	—	(14,220)
Net income (loss) available for common stock	$ 78,940	$ 160,283	$ 20,777	$ 12,899	$ 449,212	$ (456,782)	$ (6,887)	$ 258,442

(a) Income tax benefit (expense) includes a tax benefit of $73 million at our Gas Utilities resulting from legal entity restructuring. See Note 15.

Year ended December 31, 2017	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
	Consolidating Income Statement							
Revenue	$ 689,945	$ 947,595	$ 7,263	$ 35,463	$ —	$ —	$ —	$1,680,266
Intercompany revenue	14,705	35	84,283	31,158	344,685	(474,866)	—	—
Total revenue	704,650	947,630	91,546	66,621	344,685	(474,866)	—	1,680,266
Fuel, purchased power and cost of natural gas sold	268,405	409,603	—	—	151	(114,871)	—	563,288
Operations and maintenance	172,307	269,190	32,382	44,882	296,067	(302,832)	—	511,996
Depreciation, depletion and amortization	93,315	83,732	5,993	8,239	21,031	(24,064)	—	188,246
Operating income (loss)	170,623	185,105	53,171	13,500	27,436	(33,099)	—	416,736
Interest expense	(55,229)	(80,829)	(3,959)	(228)	(152,416)	154,543	—	(138,118)
Interest income	2,955	2,254	1,123	23	115,382	(120,721)	—	1,016
Other income (expense), net	1,730	(829)	(54)	2,191	330,373	(331,303)	—	2,108
Income tax benefit (expense)	(9,997)	(39,799)	10,333	(1,100)	(32,433)	(371)	—	(73,367)
Income (loss) from continuing operations	110,082	65,902	60,614	14,386	288,342	(330,951)	—	208,375
(Loss) from discontinued operations, net of tax [(a)]	—	—	—	—	—	—	(17,099)	(17,099)
Net income (loss)	110,082	65,902	60,614	14,386	288,342	(330,951)	(17,099)	191,276
Net income attributable to noncontrolling interest	—	(107)	(14,135)	—	—	—	—	(14,242)
Net income (loss) available for common stock	$ 110,082	$ 65,795	$ 46,479	$ 14,386	$ 288,342	$ (330,951)	$ (17,099)	$ 177,034

(a) Discontinued operations includes oil and gas property impairments. See Note 21.

FORM 10K

Consolidating Income Statement

Year ended December 31, 2016	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue	$ 664,330	$ 838,343	$ 7,176	$ 29,067	$ —	$ —	$ —	$1,538,916
Intercompany revenue	12,951	—	83,955	31,213	347,500	(475,619)	—	—
Total revenue	677,281	838,343	91,131	60,280	347,500	(475,619)	—	1,538,916
Fuel, purchased power and cost of natural gas sold	261,349	352,165	—	—	456	(114,838)	—	499,132
Operations and maintenance	158,134	245,826	32,636	39,576	378,744	(326,846)	—	528,070
Depreciation, depletion and amortization	84,645	78,335	4,104	9,346	22,930	(23,827)	—	175,533
Operating income (loss)	173,153	162,017	54,391	11,358	(54,630)	(10,108)	—	336,181
Interest expense	(56,237)	(76,586)	(3,758)	(401)	(114,597)	115,469	—	(136,110)
Interest income	5,946	1,573	1,983	24	97,147	(105,244)	—	1,429
Other income (expense), net	3,193	184	2	2,209	179,838	(181,032)	—	4,394
Income tax benefit (expense)	(40,228)	(27,462)	(17,129)	(3,137)	28,398	457	—	(59,101)
Income (loss) from continuing operations	85,827	59,726	35,489	10,053	136,156	(180,458)	—	146,793
(Loss) from discontinued operations, net of tax [(a)]	—	—	—	—	—	—	(64,162)	(64,162)
Net income (loss)	85,827	59,726	35,489	10,053	136,156	(180,458)	(64,162)	82,631
Net income attributable to noncontrolling interest	—	(102)	(9,559)	—	—	—	—	(9,661)
Net income (loss) available for common stock	$ 85,827	$ 59,624	$ 25,930	$ 10,053	$ 136,156	$ (180,458)	$ (64,162)	$ 72,970

(a) Discontinued operations includes oil and gas property impairments. See Note 21.

Corporate expense reallocation

In accordance with GAAP, indirect corporate operating costs previously allocated to BHEP were not reclassified to discontinued operations. These corporate operating costs for 2017 were reallocated to our operating segments; allocated interest was reclassified to Corporate and Other. Indirect corporate operating costs for 2016 were reclassified to Corporate and Other. The reallocation of these costs to our operating segments in 2017 and an estimate of how these costs could have been allocated to segments other than Corporate and Other in 2016 is as follows (in thousands):

	Year Ended	
Business Segment	December 31, 2017	December 31, 2016
Electric Utilities	$ 1,323	$ 2,079
Gas Utilities	1,571	2,292
Power Generation	177	320
Mining	101	196
Total reportable segments	3,172	4,887
Corporate and Other [(a)]	6,405	6,037
Total	$ 9,577	$ 10,924

(a) Includes interest allocations in 2017 and 2016 of approximately $4.9 million and $5.6 million, respectively.

(6) LONG-TERM DEBT

Long-term debt outstanding was as follows (dollars in thousands):

	Due Date	Interest Rate at December 31, 2018	Balance Outstanding December 31, 2018	Balance Outstanding December 31, 2017
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$ 525,000	$ 525,000
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Remarketable junior subordinated notes [(b)]	November 1, 2028	3.50%	—	299,000
Senior unsecured notes due 2019	January 11, 2019	2.50%	—	250,000
Senior unsecured notes due 2026	January 15, 2026	3.95%	300,000	300,000
Senior unsecured notes due 2027	January 15, 2027	3.15%	400,000	400,000
Senior unsecured notes due 2033	May 1, 2033	4.35%	400,000	—
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300,000	300,000
Corporate term loan due 2019	August 9, 2019	2.55%	—	300,000
Corporate term loan due 2020 [(a)]	July 30, 2020	3.16%	300,000	—
Corporate term loan due 2021	June 7, 2021	2.32%	12,921	18,664
Total Corporate debt			2,437,921	2,592,664
Less unamortized debt discount			(5,122)	(3,808)
Total Corporate debt, net			2,432,799	2,588,856
Electric Utilities				
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	75,000
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021 [(c)]	September 1, 2021	1.73%	7,000	7,000
Industrial development revenue bonds due 2027 [(c)]	March 1, 2027	1.73%	10,000	10,000
Series 94A Debt, variable rate [(c)]	June 1, 2024	1.93%	2,855	2,855
Total Electric Utilities debt			544,855	544,855
Less unamortized debt discount			(86)	(90)
Total Electric Utilities debt, net			544,769	544,765
Total long-term debt			2,977,568	3,133,621
Less current maturities			5,743	5,743
Less unamortized deferred financing costs [(d)]			20,990	18,478
Long-term debt, net of current maturities and deferred financing costs			$ 2,950,835	$ 3,109,400

(a) Variable interest rate, based on LIBOR plus a spread.
(b) See Note 12 for RSN details.
(c) Variable interest rate.
(d) Includes deferred financing costs associated with our Revolving Credit Facility of $2.3 million and $1.7 million as of December 31, 2018 and December 31, 2017, respectively.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2019	$	5,743
2020	$	505,743
2021	$	8,435
2022	$	—
2023	$	525,000
Thereafter	$	1,937,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2018.

Substantially all of the tangible utility property of South Dakota Electric and Wyoming Electric is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of South Dakota Electric and Wyoming Electric may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by South Dakota Electric and Wyoming Electric are callable, but are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Debt Transactions

On December 12, 2018, we paid off the $250 million, 2.5% senior unsecured notes due January 11, 2019. Proceeds from the November 1, 2018 Equity Unit conversion were used to pay off this debt.

On August 17, 2018, we issued $400 million principal amount, 4.350% senior unsecured notes due 2033. A portion of these notes were issued in a private exchange that resulted in the retirement of all $299 million principal amount of our RSNs due 2028. The remainder of the notes were sold for cash in a public offering, with the net proceeds being used to pay down short-term debt.

The issuance of these new senior notes was the culmination of a series of transactions that also included the contractually required remarketing of such RSNs on behalf of the holders of our Equity Units, with the proceeds being deposited as collateral to secure the obligations of those holders under the purchase contracts included in the Equity Units (see Note 12). As a result of the remarketing, the annual interest rate on such RSNs was automatically reset to 4.579% (however, because the RSNs were then immediately retired, no interest accrued at this reset rate).

On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at December 31, 2018, will now mature on July 30, 2020 and has substantially similar terms and covenants as the amended and restated Revolving Credit Facility. The interest cost associated with this term loan is determined based upon our corporate credit rating from S&P, Fitch, and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings and Eurodollar borrowings were 0.000% and 0.700%, respectively, at December 31, 2018.

On May 16, 2017, we paid down $50 million on our Corporate term loan due August 9, 2019. On July 17, 2017, we paid down an additional $50 million on the same term loan. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan.

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income (Loss) were as follows (in thousands):

Deferred Financing Costs Remaining at December 31, 2018	Amortization Expense for the years ended December 31, 2018	2017	2016
$ 20,990	$ 2,829	$ 3,349	$ 3,861

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs. In addition, the agreements governing our equity units contain restrictions on the payment of cash dividends upon any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the RSNs included in such equity units. As of December 31, 2018, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2018:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2018, the restricted net assets at our Electric and Gas Utilities were approximately $257 million.

(7) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of December 31, 2018, we were in compliance with all of these financial covenants.

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	Balance Outstanding at	
	December 31, 2018	December 31, 2017
CP Program	$ 185,620	$ 211,300

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our Corporate credit rating from S&P, Fitch, and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, at December 31, 2018. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at December 31, 2018. Margins and the commitment fee rate decreased in August 2018 due to our upgraded credit rating from S&P.

We have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net (payments) under the CP Program during 2018 were $(26) million and our notes outstanding as of December 31, 2018 were $186 million. As of December 31, 2018, the weighted average interest rate on CP Program borrowings was 2.88%.
As of December 31, 2018 and December 31, 2017, we had outstanding letters of credit totaling approximately $22 million and approximately $27 million, respectively.

Total accumulated deferred financing costs on the Revolving Credit Facility of $6.7 million are being amortized over its estimated useful life and were included in Interest expense on the accompanying Consolidated Statements of Income (Loss). See Note 6 above for additional details.

Debt Covenants

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

Our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	At December 31, 2018	Covenant Requirement at December 31, 2018	
Consolidated Indebtedness to Capitalization Ratio	59%	Less than	65%

(8) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to reclamation of coal mining sites in the Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment, retirement of gas pipelines at our Gas Utilities and asbestos at our Electric and Gas Utilities. We periodically review and update estimated costs related to these asset retirement obligations. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

The following tables present the details of AROs which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2017	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates (b)	December 31, 2018
Electric Utilities	$ 6,287	$ —	$ —	$ 269	$ 2	$ 6,558
Gas Utilities	33,238	152	—	1,237	—	34,627
Mining	12,499	—	(4)	649	2,471	15,615
Total	$ 52,024	$ 152	$ (4)	$ 2,155	$ 2,473	$ 56,800

	December 31, 2016	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates (a)	December 31, 2017
Electric Utilities	$ 4,661	$ —	$ (4)	$ 268	$ 1,362	$ 6,287
Gas Utilities	29,775	—	—	1,142	2,321	33,238
Mining	12,440	—	(107)	651	(485)	12,499
Total	$ 46,876	$ —	$ (111)	$ 2,061	$ 3,198	$ 52,024

(a) The Gas Utilities' Revision to Prior Estimates represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.
(b) The increase in the Mining Revision to Prior Estimates was primarily driven by higher costs associated with back-filling the pit with overburden removed during the mining process.

We also have legally required AROs related to certain assets within our electric transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a liability for the cost of these obligations cannot be measured at this time.

We had identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells. These obligations were classified as held for sale at December 31, 2017. See Note 21.

(9) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

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

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for several of our gas-fired generation assets, which include market fluctuations due to unpredictable factors such as weather, market speculation, pipeline constraints, and other factors that may impact natural gas supply and demand;

- Interest rate risk associated with our variable debt.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

Our credit exposure at December 31, 2018 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income (Loss) and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements) expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

For our regulated Utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2019 through December 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold. Effectiveness of our hedging position is evaluated at least quarterly.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Utilities are comprised of both short and long positions. We had the following net long positions as of:

	December 31, 2018		December 31, 2017	
	Notional (MMBtus)	Maximum Term (months) (a)	Notional (MMBtus)	Maximum Term (months) (a)
Natural gas futures purchased	4,000,000	24	8,330,000	36
Natural gas options purchased, net	4,320,000	13	3,540,000	14
Natural gas basis swaps purchased	3,960,000	24	8,060,000	36
Natural gas over-the-counter swaps, net (b)	3,660,000	24	3,820,000	29
Natural gas physical commitments, net (c)	18,325,852	30	12,826,605	35

(a) Term reflects the maximum forward period hedged.
(b) As of December 31, 2018, 1,542,000 MMBtus of natural gas over-the-counter swaps purchased were designated as cash flow hedges.
(c) Volumes exclude contracts that qualify for normal purchase, normal sales exception.

Based on December 31, 2018 prices, a $0.4 million gain would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income (Loss) is presented below for the years ended December 31, 2018, 2017 and 2016 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	December 31, 2018			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (2,851)	Interest expense	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(130)	Fuel, purchased power and cost of natural gas sold	—
Total impact from cash flow hedges		$ (2,981)		$ —

	December 31, 2017			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (2,941)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	913	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(243)	Fuel, purchased power and cost of natural gas sold	(75)
Total		$ (2,271)		$ (75)

	December 31, 2016			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (3,899)	Interest expense	$ (953)
Commodity derivatives	Net (loss) from discontinued operations	11,019	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(14)	Fuel, purchased power and cost of natural gas sold	—
Total		$ 7,106		$ (953)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the years ended December 31, 2018, 2017 and 2016. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the Consolidated Statements of Net Income (Loss) as incurred.

	December 31, 2018	December 31, 2017	December 31, 2016
	(In thousands)		
Increase (decrease) in fair value:			
Interest rate swaps	$ —	$ —	$ (31,222)
Forward commodity contracts	983	366	(573)
Recognition of (gains) losses in earnings due to settlements:			
Interest rate swaps	2,851	2,941	3,899
Forward commodity contracts	130	(670)	(11,005)
Total other comprehensive income (loss) from hedging	$ 3,964	$ 2,637	$ (38,901)

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income (Loss) for the years ended December 31, 2018, 2017 and 2016 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

		December 31, 2018	December 31, 2017	December 31, 2016
Derivatives Not Designated as Hedging Instruments	Location of Gain/ (Loss) on Derivatives Recognized in Income	Amount of Gain/ (Loss) on Derivatives Recognized in Income	Amount of Gain/ (Loss) on Derivatives Recognized in Income	Amount of Gain/ (Loss) on Derivatives Recognized in Income
Commodity derivatives	Net (loss) from discontinued operations	$ —	$ —	$ (50)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	1,101	(2,207)	940
		$ 1,101	$ (2,207)	$ 890

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to the hedges in our Utilities were $6.2 million and $12 million at December 31, 2018 and 2017, respectively.

(10) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2018 or 2017. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

A discussion of fair value of financial instruments is included in Note 11. Oil and gas derivative instruments are included in assets and liabilities held for sale discussed in Note 21. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments (in thousands):

	As of December 31, 2018				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Utilities	$ —	$ 2,927	$ —	$ (1,408)	$ 1,519
Total	$ —	$ 2,927	$ —	$ (1,408)	$ 1,519
Liabilities:					
Commodity derivatives - Utilities	$ —	$ 6,801	$ —	$ (5,794)	$ 1,007
Total	$ —	$ 6,801	$ —	$ (5,794)	$ 1,007

	As of December 31, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Utilities	$ —	1,586	$ —	$ (1,282)	$ 304
Total	$ —	$ 1,586	$ —	$ (1,282)	$ 304
Liabilities:					
Commodity derivatives - Utilities	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259
Total	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis, aside from the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in thousands):

	Balance Sheet Location	December 31, 2018	2017
Derivatives designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ 415	$ —
Noncurrent commodity derivatives	Other assets, non-current	18	—
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	(114)	(817)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(4)	(67)
Total derivatives designated as hedges		$ 315	$ (884)
Not designated as hedges:			
Asset derivative instruments:			
Current commodity derivatives	Derivative assets - current	$ 1,085	$ 304
Noncurrent commodity derivatives	Other assets, non-current	1	—
Liability derivative instruments:			
Current commodity derivatives	Derivative liabilities - current	(833)	(1,264)
Noncurrent commodity derivatives	Other deferred credits and other liabilities	(56)	(111)
Total derivatives not designated as hedges		$ 197	$ (1,071)

Derivatives Offsetting

It is our policy to offset in our Consolidated Balance Sheets contracts which provide for legally enforceable netting of our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Consolidated Balance Sheets in the following tables include the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at December 31, 2018 and 2017, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets at December 31, 2018 was as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Commodity derivative assets subject to a master netting agreement or similar arrangement	$ 1,408	$ (1,408)	$ —
Commodity derivative assets not subject to a master netting agreement or similar arrangement	1,519	—	1,519
Total derivative assets	$ 2,927	$ (1,408)	$ 1,519

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Commodity derivative liabilities subject to a master netting agreement or similar arrangement	$ 5,794	$ (5,794)	$ —
Commodity derivative liabilities not subject to a master netting agreement or similar arrangement	1,007	—	1,007
Total derivative liabilities	$ 6,801	$ (5,794)	$ 1,007

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of December 31, 2017 were as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Commodity derivative assets subject to a master netting agreement or similar arrangement	$ 1,282	$ (1,282)	$ —
Commodity derivative assets not subject to a master netting agreement or similar arrangement	304	—	304
Total derivative assets	$ 1,586	$ (1,282)	$ 304

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Commodity derivative liabilities subject to a master netting agreement or similar arrangement	$ 11,497	$ (11,497)	$ —
Commodity derivative liabilities not subject to a master netting agreement or similar arrangement	2,259	—	2,259
Total derivative liabilities	$ 13,756	$ (11,497)	$ 2,259

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 10, were as follows at December 31 (in thousands):

	2018		2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$ 20,776	$ 20,776	$ 15,420	$ 15,420
Restricted cash and equivalents [a]	$ 3,369	$ 3,369	$ 2,820	$ 2,820
Notes payable [b]	$ 185,620	$ 185,620	$ 211,300	$ 211,300
Long-term debt, including current maturities [c] [d]	$ 2,956,578	$ 3,039,108	$ 3,115,143	$ 3,350,544

(a) Carrying value approximates fair value. Cash, cash equivalents, and restricted cash are classified in Level 1 in the fair value hierarchy.
(b) Notes payable consist of commercial paper borrowings. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.
(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.
(d) Carrying amount of long-term debt is net of deferred financing costs.

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Cash and Cash Equivalents

Included in cash and cash equivalents is cash, money market mutual funds, and term deposits. As part of our cash management process, excess operating cash is invested in money market mutual funds with our bank. Money market mutual funds are not deposits and are not insured by the U.S. Government, the FDIC, or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

Notes Payable and Long-Term Debt

For additional information on our notes payable and long-term debt, see Note 6 and Note 7.

(12) EQUITY

Equity Units

On November 23, 2015, we issued 5.98 million Equity Units for total gross proceeds of $299 million. Each Equity Unit had a stated amount of $50.00 and consisted of (i) a forward purchase contract to purchase the Company's common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of RSNs due 2028.

On October 29, 2018, we announced the settlement rate for the stock purchase contracts that are components of the Equity Units issued on November 23, 2015. The settlement rate was based upon the minimum settlement rate, as adjusted to account for past dividends, because the average of the closing price per share of Black Hills Corporation common stock on the New York Stock Exchange for the 20 consecutive trading days ending on October 29, 2018 exceeded the threshold appreciation price. Each holder of the Equity Units on that date, following payment of $50.00 for each unit which it holds, received 1.0655 shares of Black Hills Corporation common stock for each such unit. The holders' obligations to make such payments were satisfied with proceeds generated by the successful remarketing on August 17, 2018, of the RSNs that formerly constituted a component of the Equity Units. See Note 6 for additional information.

Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of approximately $299 million in exchange for approximately 6.372 million shares of common stock. Proceeds were used to pay down the $250 million senior unsecured notes due January 11, 2019, with the balance used to pay down short-term debt.

At-the-Market Equity Offering Program

On August 4, 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior year program other than the aggregate value increased from $200 million to $300 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2017. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We did not issue any common shares under the ATM equity offering program during the twelve months ended December 31, 2018 and 2017. During the twelve months ended December 31, 2016, we issued an aggregate of 1,968,738 shares of common stock under the ATM equity offering program for $119 million, net of $1.2 million in commissions.

Equity Compensation Plans`

Our 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 800,180 shares available to grant at December 31, 2018.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2018, total unrecognized compensation expense related to non-vested stock awards was approximately $12 million and is expected to be recognized over a weighted-average period of 1.9 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income (Loss) was as follows for the years ended December 31 (in thousands):

	2018	2017	2016
Stock-based compensation expense	$ 12,390	$ 7,626	$ 10,885

Stock Options

The Company has not issued any stock options since 2014 and has 68,749 stock options outstanding at December 31, 2018. The amount of stock options granted during the last three years, and related exercise activity are not material to the Company's consolidated financial statements.

Restricted Stock

The fair value of restricted stock and restricted stock unit awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over 3 years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and restricted stock units at December 31, 2018, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Balance at beginning of period	267	$ 55.94
Granted	113	57.31
Vested	(119)	54.24
Forfeited	(25)	55.52
Balance at end of period	236	$ 57.50

The weighted-average grant-date fair value of restricted stock granted and the total fair value of shares vested during the years ended December 31, was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested
		(in thousands)
2018	$ 57.31	$ 6,776
2017	$ 60.63	$ 7,909
2016	$ 53.55	$ 4,602

As of December 31, 2018, there was $8.9 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 2.1 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.8 million at December 31, 2018 would be reclassified as a liability.

Outstanding performance periods at December 31 were as follows (shares in thousands):

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
January 1, 2016	January 1, 2016 - December 31, 2018	51	0%	200%
January 1, 2017	January 1, 2017 - December 31, 2019	49	0%	200%
January 1, 2018	January 1, 2018 - December 31, 2020	53	0%	200%

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value [(a)]	Shares	Weighted-Average Fair Value at December 31, 2018
	(in thousands)		(in thousands)	
Performance Shares balance at beginning of period	74	$ 55.31	74	
Granted	28	61.82	28	
Forfeited	(3)	58.14	(3)	
Vested	(22)	54.92	(22)	
Performance Shares balance at end of period	77	$ 57.66	77	$ 76.03

(a) The grant date fair values for the performance shares granted in 2018, 2017 and 2016 were determined by Monte Carlo simulation using a blended volatility of 21%, 23% and 24%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

The weighted-average grant-date fair value of performance share awards granted was as follows in the years ended:

	Weighted Average Grant Date Fair Value
December 31, 2018	$ 61.82
December 31, 2017	$ 63.52
December 31, 2016	$ 47.76

There were no performance plan payouts during the years ended December 31, 2018, 2017, and 2016.

On January 29, 2019, the Compensation Committee of our Board of Directors determined that the Company's total shareholder return for the January 1, 2016 through December 31, 2018 performance period was at the 74.8 percentile of its peer group and confirmed a payout equal to 161.9% of target shares, valued at $5.7 million. The payout was fully accrued at December 31, 2018.

As of December 31, 2018, there was $3.2 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.8 years.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued new shares until March 1, 2018, after which we began purchasing shares on the open market. At December 31, 2018, there were 253,418 shares of unissued stock available for future offering under the plan.

Preferred Stock

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding.

Sale of Noncontrolling Interest in Subsidiary

Black Hills Colorado IPP owns and operates a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third-party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes.

A partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated, is specified under ASC 810. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Net income available for common stock for the years ended December 31, 2018, 2017 and 2016 was reduced by $14 million, $14 million, and $10 million, respectively, attributable to this noncontrolling interest. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of December 31:

	2018	2017
	(in thousands)	
Assets		
Current assets	$ 13,620	$ 14,837
Property, plant and equipment of variable interest entities, net	$ 199,839	$ 208,595
Liabilities		
Current liabilities	$ 5,174	$ 4,565

(13) REGULATORY MATTERS

TCJA revenue reserve

The TCJA signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21%. Effective January 1, 2018, the key impact of tax reform on existing utility revenues/tariffs established prior to tax reform, was primarily from the change in the federal tax rate from 35% to 21% affecting current income tax expense embedded in those tariffs. Black Hills has been collaborating with utility commissions in the states in which it provides utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We have received state utility commission approvals to provide the benefits of federal tax reform to utility customers in six states. We estimated and recorded a reserve to revenue of approximately $37 million during the year ended December 31, 2018. As of December 31, 2018, $19 million has been returned to customers.

A list of states where benefits to customers of federal tax reform have been approved is summarized below.

State	Approximate 2018 Benefit for Customers	Start Date for Customer Benefits
Arkansas	$ 9.7 million	October 2018
Colorado	$ 10.8 million	July 2018
Iowa	$ 2.2 million	June 2018
Kansas	$ 1.9 million	April 2018
Nebraska	$ 3.8 million	July 2018
South Dakota	$ 7.6 million	October 2018

In support of returning benefits to customers, the three rate review requests filed in 2017 for Arkansas Gas, Wyoming Gas (Northwest Wyoming) and Rocky Mountain Natural Gas (a pipeline system in Colorado) were adjusted to include the benefits to customers of federal tax reform as discussed below.

Excess Deferred Income Taxes

As of December 31, 2018 and 2017, we have a regulatory liability associated with TCJA related items of approximately $311 million and $301 million, respectively. The majority of this regulatory liability relates to excess deferred taxes resulting from the remeasurement of deferred tax assets and liabilities in 2017. A majority of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets. As of December 31, 2018, the Company has amortized $2.1 million of this regulatory liability. The portion that was eligible for amortization under the average rate assumption method in 2018, but is awaiting resolution of the treatment of these amounts in future regulatory proceedings, has not been recognized and may be refunded in customer rates at any time in accordance with the resolution of pending or future regulatory proceedings. See Note 15 for more information.

Electric Utilities Regulatory Activity

Corriedale Wind Project

On December 17, 2018, South Dakota Electric and Wyoming Electric filed a joint application with the WPSC for a CPCN to construct a new $57 million, 40 MW wind generation project near Cheyenne, Wyoming. If approved, the 40 MW Corriedale Wind Energy Project would be jointly owned by South Dakota Electric and Wyoming Electric. The project would be largely constructed and placed in service during 2020.

Wyoming Electric Integrated Resource Plan

On November 30, 2018, Wyoming Electric submitted its 2018 integrated resource plan to the WPSC, which included the recommendation that Wyoming Electric acquire Wygen I. Review of Wyoming Electric's integrated resource plan is subject to an open public process governed by the WPSC. The purchase of Wygen I would require approval of a CPCN by the WPSC and approval by FERC. The review process is expected to be completed by year-end 2019.

Wyoming Electric Settlement

On October 31, 2018, Wyoming Electric received approval from the WPSC for a comprehensive, multi-year settlement regarding its PCA Application filed earlier in 2018. Wyoming Electric's PCA permits the recovery of costs associated with fuel, purchased electricity and other specified costs, including the portion of the company's energy that is delivered from the Wygen I PPA with Black Hills Wyoming. Wyoming Electric will provide a total of $7.0 million in customer credits through the PCA mechanism in 2018, 2019 and 2020 to resolve all outstanding issues relating to its current and prior PCA filings. The settlement also stipulates the adjustment for the variable cost segment of the Wygen I PPA with Wyoming Electric will escalate by 3.0% annually through 2022, providing price certainty for Wyoming Electric and its customers. As of December 31, 2018, we have recorded a liability of $6.0 million related to the PCA.

South Dakota Electric Common Use System (CUS)

The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2019 the annual revenue requirement increased by $1.9 million and included estimated weighted average capital additions of $31 million for 2018 and 2019. The annual transmission revenue requirement has a true up mechanism that is posted in June of each year.

South Dakota Electric Settlement

On June 16, 2017, South Dakota Electric received approval from the SDPUC on a settlement reached with the SDPUC staff agreeing to a 6-year moratorium period effective July 1, 2017. As part of this agreement, South Dakota Electric will not increase base rates, absent an extraordinary event. The moratorium period also includes suspension of both the Transmission Facility Adjustment and the Environmental Improvement Adjustment, and a $1.0 million increase to the annual power marketing margin guarantee during this period. Additionally, existing regulatory asset balances as of the settlement date of approximately $13 million related to decommissioning and Winter Storm Atlas are being amortized over the moratorium period. These balances were previously being amortized over a 10-year period ending September 30, 2024. The vegetation management regulatory asset as of the settlement date of $14 million, previously unamortized, is also being amortized over the moratorium period. The change in amortization periods for these costs increased annual amortization expense by approximately $2.7 million. The June 16, 2017 settlement had no impact to base rates.

Gas Utilities Regulatory Activity

Colorado Gas

On October 10, 2018, we received approval from the CPUC for a request to consolidate our Colorado gas utility operations into a new utility entity. The Colorado portion of Black Hills Gas Distribution, LLC, will be combined with Black Hills/Colorado Gas Utility Company, Inc., into a new company named Black Hills Colorado Gas, Inc. The two companies being merged currently serve 187,000 Colorado customers doing business as Black Hills Energy. On February 1, 2019, Colorado Gas filed a rate review with the CPUC requesting approval to consolidate the base rate areas, tariffs, terms and conditions and adjustment clauses of its two legacy utilities. The rate review also requests $2.5 million in new revenue to recover costs and investments in safety, reliability and system integrity.

Wyoming Gas

On November 20, 2018, we received approval from the WPSC for a CPCN to construct a new $54 million, 35-mile natural gas pipeline to enhance supply reliability and delivery capacity for approximately 57,000 customers in central Wyoming. The pipeline, known as the Natural Bridge Pipeline, is planned to be placed in service in late 2019.

Arkansas Gas
On October 5, 2018, Arkansas Gas received approval from the APSC for a general rate increase. The new rates will generate approximately $12 million of new annual revenue. The APSC's approval also allows Arkansas Gas to include $11 million of revenue that is currently being collected through certain rider mechanisms in the new base rates. The new revenue increase is based on a return on equity of 9.61% and a capital structure of 49.1% equity and 50.9% debt. New rates, inclusive of customer benefits related to the TCJA, were effective October 15, 2018.

Wyoming Gas
On July 16, 2018, the WPSC reached a bench decision approving our Wyoming Gas (Northwest Wyoming) settlement and stipulation with the OCA. We received the final order in the third quarter of 2018. The settlement provides for $1.0 million of new revenue, a return on equity of 9.6%, and a capital structure of 54.0% equity and 46.0% debt. New rates, inclusive of customer benefits related to the TCJA, were effective September 1, 2018.

Kansas Gas
On June 19, 2018, Kansas Gas received approval from the Kansas Corporation Commission for an annual increase in revenue of $0.6 million based on inclusion of approximately $8.0 million of eligible capital investments under the Gas System Reliability Rider. The Kansas Legislature passed legislation in 2018 enabling the annual eligible investments to double from approximately $8.0 million to $16 million effective January 1, 2019.

RMNG
In Colorado, new rates for RMNG went into effect June 1, 2018 after we reached a settlement which was approved by the CPUC. The settlement included $1.1 million in annual revenue increases and an extension of the SSIR to recover costs from 2018 through December 31, 2021. The annual increase is based on a return on equity of 9.9% and a capital structure of 46.63% equity and 53.37% debt. New rates are inclusive of customer benefits related to the TCJA.

Nebraska Gas
On June 1, 2018, Nebraska Gas Distribution filed an application with the NPSC requesting a continuation of the SSIR beyond the expiration date of October 31, 2019. On September 5, 2018, the NPSC approved continuation of the SSIR tariff to December 31, 2020. The SSIR provides approximately $6.0 million of revenue annually on investments made prior to January 1, 2018, with investments after that date to be recovered through other methods. If a base rate review is filed prior to expiration of the rider, that rate request will include the remaining investment to be recovered.

On October 2, 2017, Nebraska Gas Distribution filed with the NPSC requesting recovery of $6.8 million, which includes $0.3 million of increased annual revenue related to system safety and integrity expenditures on projects for the period of 2012 through 2017. This SSIR tariff was approved by the NPSC in January 2018, and went into effect on February 1, 2018.

(14) OPERATING LEASES

We have entered into lease agreements for office facilities, communication tower sites, land and equipment. Rental expense incurred under these operating leases, including month to month leases, for the years ended December 31 was as follows (in thousands):

	2018	2017	2016
Rent expense [a]	$ 2,667	$ 10,325	$ 9,568

(a) The decrease in rent expense is primarily driven by current year expiration of office leases and by purchases of facilities previously leased.

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2019	$ 1,052
2020	$ 464
2021	$ 344
2022	$ 224
2023	$ 216
Thereafter	$ 1,776

FORM 10K

(15) INCOME TAXES

TCJA

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company's future results of operations, cash flows or financial position. As a result of the revaluation at December 31, 2017, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. During the year ended December 31, 2018 we recorded approximately $11 million of additional regulatory liability associated with TCJA related items primarily related to property, completing the revaluation of deferred taxes pursuant to the TCJA. A majority of the excess deferred taxes are subject to the average rate assumption method, as prescribed by the IRS, and will generally be amortized as a reduction of customer rates over the remaining lives of the related assets. As of December 31, 2018, the Company has amortized $2.1 million of the regulatory liability. The portion that was eligible for amortization under the average rate assumption method in 2018, but is awaiting resolution of the treatment of these amounts in future regulatory proceedings, has not been recognized and may be refunded in customer rates at any time in accordance with the resolution of pending or future regulatory proceedings.

Tax benefit related to legal entity restructuring

As part of the Company's ongoing efforts to continue to integrate the legal entities that the Company has acquired in recent years, certain legal entity restructuring transactions occurred on March 31, 2018 and December 31, 2018. As a result of these transactions, additional deferred income tax assets of $73 million, related to goodwill that is amortizable for tax purposes, were recorded and deferred tax benefits of $73 million were recorded to income tax benefit (expense) on the Consolidated Statements of Income. Due to this being a common control transaction, it had no effect on the other assets and liabilities of these entities.

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2018	2017	2016
Current:			
Federal	$ 325	$ (6,193)	$ (21,806)
State	247	(1,432)	(1,797)
	572	(7,625)	(23,603)
Deferred:			
Federal	(23,295)	76,567	78,997
State	815	4,470	3,759
Excess deferred tax amortization	(1,727)	—	—
Tax credit amortization	(32)	(45)	(52)
	(24,239)	80,992	82,704
	$ (23,667)	$ 73,367	$ 59,101

Included in discontinued operations is a tax benefit of $2.6 million, $8.4 million and $49 million for 2018, 2017 and 2016, respectively.

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2018	2017
Deferred tax assets:		
Regulatory liabilities	$ 92,966	$ 90,742
Employee benefits	14,039	18,724
Federal net operating loss	139,371	155,276
Other deferred tax assets[a]	101,579	74,561
Less: Valuation allowance	(11,809)	(9,121)
Total deferred tax assets	336,146	330,182
Deferred tax liabilities:		
Accelerated depreciation, amortization and other property-related differences	(529,338)	(510,774)
Regulatory assets	(32,324)	(26,245)
Goodwill [b]	(602)	(46,392)
State deferred tax liability	(64,095)	(58,930)
Deferred costs	(13,351)	(16,063)
Other deferred tax liabilities	(7,767)	(8,298)
Total deferred tax liabilities	(647,477)	(666,702)
Net deferred tax liability	$ (311,331)	$ (336,520)

(a) Other deferred tax assets consist primarily of alternative minimum tax credit and federal research and development credits. No single item exceeds 5% of the total net deferred tax liability.
(b) Legal entity restructuring - see above.

FORM 10K

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2018	2017	2016
Federal statutory rate	21.0 %	35.0%	35.0%
State income tax (net of federal tax effect)	2.3	0.9	1.2
Percentage depletion	(0.4)	(0.6)	(0.8)
Non-controlling interest [(a)]	(1.3)	(1.8)	(1.6)
Equity AFUDC	—	(0.2)	(0.5)
Tax credits	(2.0)	(1.7)	(0.4)
Transaction costs	—	—	0.5
Accounting for uncertain tax positions adjustment	—	(0.2)	(2.7)
Flow-through adjustments [(b)]	(1.6)	(1.1)	(2.1)
Jurisdictional simplification project [(d)]	(28.5)	—	—
Other tax differences	(0.4)	(0.9)	0.1
IRC 172(f) carryback claim	—	(0.7)	—
TCJA corporate rate reduction [(c)]	1.6	(2.7)	—
	(9.3)%	26.0%	28.7%

(a) The effective tax rate reflects the income attributable to the noncontrolling interest in Black Hills Colorado IPP for which a tax provision was not recorded.

(b) Flow-through adjustments related primarily to accounting method changes for tax purposes that allow us to take a current tax deduction for repair costs and certain indirect costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.

(c) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21% effective January 1, 2018. The 2017 effective tax rate reduction reflects the revaluation of deferred income taxes associated with non-regulated operations required by the change. During the year ended December 31, 2018, we recorded approximately $4.0 million of additional tax expense associated with changes in the prior estimated impacts of TCJA related items. During the year ended December 31, 2017, we recorded approximately $8.0 million of tax benefit resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017.

(d) Legal entity restructuring - see above.

At December 31, 2018, we have federal and state NOL carryforwards that will expire at various dates as follows (in thousands):

	Amounts		Expiration Dates		
Federal Net Operating Loss Carryforward	$	663,741	2021	to	2038
State Net Operating Loss Carryforward	$	542,632	2019	to	2038

As of December 31, 2018, we had a $0.4 million valuation allowance against the state NOL carryforwards. Our 2018 analysis of the ability to utilize such NOLs resulted in a $0.4 million increase in the valuation allowance offset by a $1.2 million decrease from expired NOL. This resulted in an increase to tax expense of $0.4 million and a decrease to the state NOL carryforward of $1.2 million. The valuation allowance adjustment was primarily attributable to a projected decrease in state taxable income for years beyond 2018. This projected decrease impacted the utilization of NOL carryforward in those states where the carryforward period is significantly shorter than the federal carryforward period of 20 years. In certain states, the carryforward period is limited to 5 years. Ultimate usage of these NOLs depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	Changes in Uncertain Tax Positions
Beginning balance at January 1, 2016	$ 31,986
Additions for prior year tax positions	2,423
Reductions for prior year tax positions	(19,174)
Additions for current year tax positions	—
Settlements	(11,643)
Ending balance at December 31, 2016	3,592
Additions for prior year tax positions	358
Reductions for prior year tax positions	(5,713)
Additions for current year tax positions	5,026
Settlements	—
Ending balance at December 31, 2017	3,263
Additions for prior year tax positions	251
Reductions for prior year tax positions	(417)
Additions for current year tax positions	486
Settlements	—
Ending balance at December 31, 2018	$ 3,583

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.1 million.

We recognized no interest expense associated with income taxes for the years ended December 31, 2018, December 31, 2017 and December 31, 2016. We had no accrued interest (before tax effect) associated with income taxes at December 31, 2018 and December 31, 2017.

The Company is subject to federal income tax as well as income tax in various state and local jurisdictions. Black Hills Gas, Inc. and subsidiaries, which files a separate consolidated tax return from Black Hills Corporation and subsidiaries through March 31, 2018, is under examination by the IRS for 2014. Black Hills Corporation is no longer subject to examination for tax years prior to 2015.

We had deferred a substantial amount of tax payments through various tax planning strategies including the deferral of approximately $125 million in income taxes attributable to the like-kind exchange effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. The IRS had challenged our position with respect to the like-kind exchange. In the first quarter of 2016, we reached a settlement agreement in principle with IRS Appeals related to both the like-kind exchange transaction in addition to the R&D credits and deductions issues. In 2016, the settlement resulted in a reduction to the liability for unrecognized tax benefits of approximately $29 million excluding interest. Approximately $17 million of the reduction was to restore accumulated deferred income taxes and the remaining portion of approximately $12 million was reclassified to current taxes payable.

As of December 31, 2018, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2019.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2018, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards			Expiration Year		
Investment tax credit	$	20,285	2023	to	2036
Research and development	$	180		No expiration	

As of December 31, 2018, we had an $11 million valuation allowance against the state tax credit carryforwards. Our ability to utilize such credits resulted in an increase of the valuation allowance of approximately $3.5 million of which approximately $1.9 million resulted in an increase to tax expense. The remaining $1.6 million increase is attributable to our regulated business and is being accounted for under the deferral method whereby the credits are amortized to tax expense over the estimated useful life of the underlying asset that generated the credit. The valuation allowance adjustment was primarily attributable to the impact of lower projected apportionment factors resulting in decreased state taxable income in years beyond 2018. Ultimate usage of these credits depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the state tax credit carryforwards, the offsetting amount will affect tax expense.

(16) OTHER COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Consolidated Statements of Income (Loss) for the period, net of tax (in thousands):

		Amount Reclassified from AOCI	
	Location on the Consolidated Statements of Income (Loss)	December 31, 2018	December 31, 2017
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ (2,851)	$ (2,941)
Commodity contracts	Net (loss) from discontinued operations	—	913
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(130)	(243)
		(2,981)	(2,271)
Income tax	Income tax benefit (expense)	630	875
Total reclassification adjustments related to cash flow hedges, net of tax		$ (2,351)	$ (1,396)
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$ 178	$ 168
Prior service cost	Net (loss) from discontinued operations	—	29
Actuarial gain (loss)	Operations and maintenance	(2,487)	(1,599)
Actuarial gain (loss)	Net (loss) from discontinued operations	—	(58)
		(2,309)	(1,460)
Income tax	Income tax benefit (expense)	543	(516)
Total reclassification adjustments related to defined benefit plans, net of tax		(1,766)	(1,976)
Total reclassifications		$ (4,117)	$ (3,372)

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

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2017	$ (19,581)	$ (518)	$ (21,103)	$ (41,202)
Other comprehensive income (loss) before reclassifications	—	755	2,155	2,910
Amounts reclassified from AOCI	2,252	99	1,766	4,117
Reclassification to regulatory asset	—	—	6,519	6,519
Reclassification of certain tax effects from AOCI	22	(8)	726	740
As of December 31, 2018	$ (17,307)	$ 328	$ (9,937)	$ (26,916)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2016	$ (18,109)	$ (233)	$ (16,541)	$ (34,883)
Other comprehensive income (loss) before reclassifications	—	231	(1,890)	(1,659)
Amounts reclassified from AOCI	1,912	(516)	944	2,340
Reclassification of certain tax effects from AOCI	(3,384)	—	(3,616)	(7,000)
As of December 31, 2017	$ (19,581)	$ (518)	$ (21,103)	$ (41,202)

(17) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended December 31,	2018	2017	2016
		(in thousands)	
Non-cash investing activities and financing from continuing operations -			
Property, plant and equipment acquired with accrued liabilities	$ 69,017	$ 28,191	$ 27,034
Increase (decrease) in capitalized assets associated with asset retirement obligations	$ 2,625	$ 3,198	$ 8,577
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amount capitalized)	$ (137,965)	$ (132,428)	$ (113,627)
Income taxes (paid) refunded	$ (14,730)	$ 1,775	$ (1,156)

(18) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation in the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plan provides a Company matching contribution for all eligible participants. Certain eligible participants who are not currently accruing a benefit in the Pension Plan also receive a Company retirement contribution based on the participant's age and years of service. Vesting of all Company and matching contributions occurs at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

The SourceGas Retirement Savings Plan was merged into the Black Hills Corporation Retirement Savings Plan effective December 31, 2017. The plan design of the Black Hills Corporation 401(k) Plan applies to all eligible employees as of January 1, 2018.

Defined Benefit Pension Plan (Pension Plan)

We have one defined benefit pension plan, the Black Hills Retirement Plan (Pension Plan). The Pension Plan covers certain eligible employees of the Company. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan is closed to new employees and frozen for certain employees who did not meet age and service based criteria.

The Pension Plan assets are held in a Master Trust. Our Board of Directors has approved the Pension Plan's investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plan's beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan's benefit payment obligations. The Pension Plan's assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns, and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2018, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 29% to 37% return-seeking assets and 63% to 71% liability-hedging assets.

Our Pension Plan is funded in compliance with the federal government's funding requirements.

Plan Assets

The percentages of total plan asset by investment category for our Pension Plan at December 31 were as follows:

	2018	2017
Equity	17%	26%
Real estate	4	4
Fixed income	71	63
Cash	3	1
Hedge funds	5	6
Total	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

Plan Assets

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plans

BHC sponsors retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans for participating business units are pre-funded via VEBAs. Pre-65 retirees as well as a grandfathered group of post-65 Cheyenne Light, Fuel and Power ("CLFP") retirees and a grandfathered group of post-65 former SourceGas employees who retired prior to January 1, 2017 receive their retiree medical benefits through the Black Hills self-insured retiree medical plans.

Healthcare coverage for Medicare-eligible BHC and Black Hills Utility Holdings retirees is provided through an individual market healthcare exchange. Medicare-eligible SourceGas employees who retired after December 31, 2016 also receive retiree medical coverage through an individual market healthcare exchange.

Plan Assets

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Utility Holding and SourceGas Postretirement - AWG Plans provide for partial pre-funding via VEBAs and a Grantor Trust. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees located in the states of Arkansas, Kansas and Iowa. We do not pre-fund the Healthcare Plans for those employees outside Arkansas, Kansas and Iowa.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Healthcare benefits include company and participant paid premiums. Contributions for the years ended December 31 were as follows (in thousands):

	2018	2017
Defined Contribution Plan		
Company retirement contribution	$ 8,766	$ 10,223
Matching contributions	$ 13,559	$ 9,811

	2018	2017
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 12,700	$ 27,700
Non-Pension Defined Benefit Postretirement Healthcare Plans	$ 5,298	$ 4,332
Supplemental Non-Qualified Defined Benefit Plans	$ 2,073	$ 3,217

While we do not have required contributions, we expect to make approximately $13 million in contributions to our Pension Plan in 2019.

Fair Value Measurements

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels.

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

Pension Plan	December 31, 2018					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
AXA Equitable General Fixed Income	$ —	$ 1,867	$ —	$ 1,867	$ —	$ 1,867
Common Collective Trust - Cash and Cash Equivalents	—	9,923	—	9,923	—	9,923
Common Collective Trust - Equity	—	67,457	—	67,457	—	67,457
Common Collective Trust - Fixed Income	—	279,148	—	279,148	—	279,148
Common Collective Trust - Real Estate	—	67	—	67	13,551	13,618
Hedge Funds	—	—	—	—	18,783	18,783
Total investments measured at fair value	$ —	$ 358,462	$ —	$ 358,462	$ 32,334	$ 390,796

Pension Plan	December 31, 2017					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
AXA Equitable General Fixed Income	$ —	$ 1,280	$ —	$ 1,280	$ —	$ 1,280
Common Collective Trust - Cash and Cash Equivalents	—	2,184	—	2,184	—	2,184
Common Collective Trust - Equity	—	109,496	—	109,496	—	109,496
Common Collective Trust - Fixed Income	—	262,329	—	262,329	—	262,329
Common Collective Trust - Real Estate	—	1,728	—	1,728	15,701	17,429
Hedge Funds	—	—	—	—	23,625	23,625
Total investments measured at fair value	$ —	$ 377,017	$ —	$ 377,017	$ 39,326	$ 416,343

(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plan's benefit obligations and fair value of plan assets above.

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2018					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV (a)	Total Investments
Cash and Cash Equivalents	$ 4,873	$ —	$ —	$ 4,873	$ —	$ 4,873
Equity Securities	1,005	—	—	1,005	—	1,005
Intermediate-term Bond	—	2,284	—	2,284	—	2,284
Total investments measured at fair value	$ 5,878	$ 2,284	$ —	$ 8,162	$ —	$ 8,162

Non-pension Defined Benefit Postretirement Healthcare Plans

December 31, 2017	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Investments
Cash and Cash Equivalents	$ 4,671	$ —	$ —	$ 4,671	$ —	$ 4,671
Equity Securities	1,374	—	—	1,374	—	1,374
Intermediate-term Bond	—	2,576	—	2,576	—	2,576
Total investments measured at fair value	$ 6,045	$ 2,576	$ —	$ 8,621	$ —	$ 8,621

(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plans' benefit obligations and fair value of plan assets above.

Additional information about assets of the benefit plans, including methods and assumptions used to estimate the fair value of these assets, is as follows:

Cash and Cash Equivalents: This represents an investment in Invesco Treasury Portfolio, which is a short-term investment trust, as well as an investment in Northern Institutional Government Assets Portfolio, which is described as a government money market fund. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Equity Securities: These represent investments in a combination of equity positions for mainly large cap core allocation and Exchange Trade Funds (ETFs) for diversification into the other sectors of the economy. ETFs are a basket of securities traded like individual stocks on the exchange. Value of equity securities held at year end are based on published market quotations of active markets. The ETF funds can be redeemed on a daily basis at their market price and have no redemption restrictions. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Intermediate-term bond: This is comprised of a diversified pool of high quality, individual municipal bonds. Pricing is evaluated using multi-dimensional relational models, as well as a series of matrices using Standard Inputs, including Municipal Securities Rule Making Board (MSRB) reported trades and material event notices, plus Municipal Market Data (MMD) benchmark yields and new issue data. As the models use observable inputs and standard data, the investments are categorized as Level 2.

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately placed bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates of loans with similar characteristics. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer. The Plan's investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

Common Collective Trust-Real Estate Fund: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund. The funds without participant withdrawal limitations are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

Common Collective Trust-Real Estate Fund: This is the same fund as above except that certain of the funds' assets contain participant withdrawal policies with restrictions on redemption and are therefore not included in the fair value hierarchy.

Hedge Funds: These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. 20% of the shares may be redeemed at the end of each month with a 10-day notice and full redemptions are available at the end of each quarter with 45-day notice, and is limited to a percentage of the total net assets value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

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Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the Consolidated Balance Sheets, components of the net periodic expense and elements of AOCI:

Benefit Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31 (in thousands),	2018	2017	2018	2017	2018	2017
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 474,725	$ 440,179	$ 45,112	$ 43,869	$ 69,339	$ 68,023
Service cost	6,834	7,034	1,764	2,937	2,291	2,300
Interest cost	15,470	15,520	1,170	1,276	2,085	2,141
Actuarial (gain) loss	(31,340)	36,661	(2,963)	247	(9,045)	(396)
Amendments	—	—	—	—	—	265
Benefits paid	(20,308)	(24,669)	(2,073)	(3,217)	(5,298)	(4,332)
Plan participants' contributions	—	—	—	—	1,445	1,338
Projected benefit obligation at end of year	$ 445,381	$ 474,725	$ 43,010	$ 45,112	$ 60,817	$ 69,339

Employee Benefit Plan Assets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans (a)	
As of December 31 (in thousands),	2018	2017	2018	2017	2018	2017
Change in fair value of plan assets:						
Beginning fair value of plan assets	$ 416,343	$ 364,695	$ —	$ —	$ 8,621	$ 8,470
Investment income (loss)	(17,939)	48,617	—	—	(149)	120
Employer contributions	12,700	27,700	2,073	3,217	3,543	3,025
Retiree contributions	—	—	—	—	1,445	1,338
Benefits paid	(20,308)	(24,669)	(2,073)	(3,217)	(5,298)	(4,332)
Ending fair value of plan assets	$ 390,796	$ 416,343	$ —	$ —	$ 8,162	$ 8,621

(a) Assets of VEBAs and Grantor Trust.

The funded status of the plans and the amounts recognized in the Consolidated Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2018	2017	2018	2017	2018	2017
Regulatory assets	$ 82,919	$ 72,756	$ —	$ —	$ 6,655	$ 11,507
Current liabilities	$ —	$ —	$ 1,463	$ 1,372	$ 3,885	$ 4,423
Non-current assets	$ —	$ —	$ —	$ —	$ 249	$ 69
Non-current liabilities	$ 54,585	$ 58,381	$ 41,547	$ 43,739	$ 49,015	$ 56,365
Regulatory liabilities	$ 4,620	$ 5,232	$ —	$ —	$ 5,207	$ 3,334

Accumulated Benefit Obligation

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31 (in thousands)	2018	2017	2018	2017	2018	2017
Accumulated Benefit Obligation	$ 428,851	$ 450,394	$ 40,530	$ 41,243	$ 60,817	$ 69,339

Components of Net Periodic Expense

Net periodic expense consisted of the following for the year ended December 31 (in thousands):

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Service cost	$ 6,834	$ 7,034	$ 7,619	$ 1,764	$ 1,546	$ 1,335	$ 2,291	$ 2,300	$ 1,757
Interest cost	15,470	15,520	15,743	1,170	1,276	1,257	2,085	2,141	1,942
Expected return on assets	(24,741)	(24,517)	(23,062)	—	—	—	(315)	(315)	(279)
Net amortization of prior service cost	58	58	58	2	2	2	(398)	(411)	(428)
Recognized net actuarial loss (gain)	8,632	4,007	7,173	1,000	1,001	829	216	499	335
Settlement expense[(a)]	—	—	10	—	—	—		—	—
Net periodic expense	$ 6,253	$ 2,102	$ 7,541	$ 3,936	$ 3,825	$ 3,423	$ 3,879	$ 4,214	$ 3,327

(a) Settlement expense is the result of lump-sum payments on the SourceGas Retirement Plan in excess of interest and service costs for the year.

For the year ended December 31, 2018, service costs were recorded in Operations and maintenance expense while non-service costs were recorded in Other expense, on the Consolidated Statements of Income. For the years ended December 31, 2017 and 2016, service costs and non-service costs were recorded in Operations and maintenance expense. Because prior years' costs were not considered material, they were not reclassified on the Consolidated Statements of Income. See Note 1 for additional information.

AOCI

For defined benefit plans, amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2018	2017	2018	2017	2018	2017
Net (gain) loss	$ 11,967	$ 10,056	$ 4,668	$ 6,639	$ 860	$ 1,309
Prior service cost (gain)	1	21	3	4	(317)	(542)
Reclassification of certain tax effects from AOCI	(594)	2,087	(87)	1,371	(45)	158
Reclassification to regulatory asset	(5,600)	—	—	—	(919)	—
Total AOCI	$ 5,774	$ 12,164	$ 4,584	$ 8,014	$ (421)	$ 925

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine benefit obligations:	2018	2017	2016	2018	2017	2016	2018	2017	2016
Discount rate	4.40%	3.71%	4.27%	4.34%	3.56%	4.02%	4.28%	3.60%	3.96%
Rate of increase in compensation levels	3.52%	3.43%	3.47%	5.00%	5.00%	5.00%	N/A	N/A	N/A

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2018	2017	2016	2018	2017	2016	2018	2017	2016
Discount rate [(a)]	3.71%	4.27%	4.50%	3.67%	4.02%	4.28%	3.60%	4.05%	4.18%
Expected long-term rate of return on assets [(b)]	6.25%	6.75%	6.87%	N/A	N/A	N/A	3.93%	3.88%	3.83%
Rate of increase in compensation levels	3.43%	3.47%	3.42%	5.00%	5.00%	5.00%	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 4.40% for the calculation of the 2019 net periodic pension costs.

(b) The expected rate of return on plan assets is 6.00% for the calculation of the 2019 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	2018	2017
Trend Rate - Medical		
Pre-65 for next year - All Plans	6.70%	7.00%
Pre-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2027	2027
Post-65 for next year - All Plans	4.94%	5.00%
Post-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2026	2026

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. See "Pension and Postretirement Benefit Obligations" within our Critical Accounting Policies in Item 7 on Form 10-K for additional details.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-Pension Defined Benefit Postretirement Healthcare Plans
2019	$ 24,405	$ 1,463	$ 4,898
2020	$ 25,847	$ 1,406	$ 5,545
2021	$ 26,951	$ 1,617	$ 5,695
2022	$ 27,972	$ 1,727	$ 5,849
2023	$ 29,002	$ 1,912	$ 5,607
2024-2028	$ 151,915	$ 12,208	$ 24,953

(19) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

Through our subsidiaries, we have the following significant long-term power purchase contracts with non-affiliated third-parties:

- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- South Dakota Electric's PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.

- South Dakota Electric's firm point-to-point transmission service agreement with PacifiCorp expiring December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- Wyoming Electric's PPA with Duke Energy's Happy Jack wind site, expiring September 3, 2028, provides up to 30 MW of wind energy from Happy Jack to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 50% of the facility output to South Dakota Electric.

- Wyoming Electric's PPA with Duke Energy's Silver Sage wind site, expiring September 30, 2029, provides up to 30 MW of wind energy. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of energy from Silver Sage to South Dakota Electric.

- South Dakota Electric's PPA with Platte River Power Authority (PRPA) to purchase up to 12 MW of wind energy through PRPA's agreement with Silver Sage. This agreement will expire September 30, 2029.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2018	2017	2016
PPA with PacifiCorp	$ 13,681	$ 13,218	$ 12,221
Transmission services agreement with PacifiCorp	$ 1,742	$ 1,671	$ 1,428
PPA with Happy Jack	$ 3,884	$ 3,846	$ 3,836
PPA with Silver Sage	$ 5,376	$ 4,934	$ 4,949
Busch Ranch I Wind Farm [(a)]	$ —	$ 1,966	$ 2,071
PPA with Platte River Power Authority	$ 223	$ —	$ —
PPAs with Cargill [(b)]	$ —	$ —	$ 10,995

(a) On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest of the Busch Ranch I Wind Farm from AltaGas. Black Hills Electric Generation and Colorado Electric now collectively own 100% of the wind farm.
(b) PPAs with Cargill expired on December 31, 2016.

Power Purchase Agreement - Related Party

On December 11, 2018, Black Hills Electric Generation purchased a 50% ownership interest in the 29 MW Busch Ranch I Wind Farm, previously owned by AltaGas. Black Hills Electric Generation will provide its 14.5 MW share of energy from the wind farm to Colorado Electric through a new PPA that replaces the PPA that Colorado Electric had with AltaGas, expiring in October 2037.

Other Gas Supply Agreements

Our Utilities also purchase natural gas, including transportation and storage capacity to meet customers' needs, under short-term and long-term purchase contracts. These contracts extend to 2044.

Purchase Commitments

We maintain natural gas supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated baseload gas volumes are established prior to the beginning of the month under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month based on requirements in accordance with the terms of the individual contract.

Our Gas Utilities segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and are therefore, for purposes of this disclosure, carried out for 60 days. At December 31, 2018, the long-term commitments to purchase quantities of natural gas under contracts indexed to the following forward indices were as follows (in MMBtus):

	CIG Rockies	NNG-Ventura	NWPL-Wyoming	Other
2019	5,803,117	3,650,000	720,000	236
2020	75,075	3,660,000	0	0
2021	0	3,650,000	0	0
2022	0	1,810,000	0	0
2023	0	0	0	0
Thereafter	0	0	0	0

Purchases under these contracts totaled $27 million, $65 million and $31 million for 2018, 2017 and 2016, respectively.

The following is a schedule of unconditional purchase obligations required under the power purchase, transmission services, coal and natural gas transportation and storage agreements (in thousands):

	Power Purchase Agreements	Transportation and storage agreements
2019	$ 22,092	$ 129,018
2020	$ 6,837	$ 127,326
2021	$ 6,203	$ 118,707
2022	$ 6,203	$ 92,635
2023	$ 6,204	$ 73,919
Thereafter	$ —	$ 148,363

Future Purchase Agreement - Related Party

Wyoming Electric's PPA for 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility expiring on December 31, 2022, includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership in the Wygen I facility. The purchase price related to the option is $2.1 million per MW which is the equivalent per MW of the pre-construction estimated cost of the Wygen III plant, which was completed in April 2010. This option purchase price is adjusted for capital additions and reduced by an amount equal to annual depreciation based on a 35-year life starting January 1, 2009. The purchase option would be subject to WPSC and FERC approval in order to obtain regulatory treatment.

Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- South Dakota Electric has an agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, which expires September 3, 2019, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- South Dakota Electric has a PPA with MEAN expiring May 31, 2028. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

- South Dakota Electric has an agreement through December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals.

Related Party Lease

Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease whereby Colorado Electric, as lessee, has included the combined-cycle turbines as property, plant and equipment along with the related lease obligation and Black Hills Colorado IPP, as lessor, has recorded a lease receivable. Segment revenue and expenses associated with the PPA have been impacted by the lease accounting. The effect of the lease accounting is eliminated in corporate consolidations.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Wyoming Electric for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Wyoming Electric's Letter of Credit attached to these bonds.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. Laws and regulations can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, permanently retired on March 21, 2014, had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed in 2013 with the state providing closure certification in 2014. Post closure monitoring activities will continue for 30 years following the closure certification date.

In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed with the state providing closure certification in 2014. Post closure monitoring will continue for 30 years following the closure certification date.

Our W.N. Clark plant, which has been retired, previously delivered coal ash to a permitted, privately-owned landfill. While we do not believe that any substances from our solid waste disposal activities will pollute underground water, we can provide no assurance that pollution will not occur over time. In this event, we could incur material costs to mitigate any resulting damages.

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond of $4.1 million with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its land lease for Busch Ranch I, Colorado Electric is required to reclaim all land where it has placed wind turbines. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 8 for additional information.

Manufactured Gas Processing

As a result of the Aquila Transaction, we acquired whole and partial liabilities for former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.1 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. We also have a $1.0 million regulatory asset for manufactured gas processing sites; see Note 1.

As of December 31, 2018, our estimated liabilities for Iowa's MGP site currently range from approximately $2.6 million to $6.1 million for which we had $2.6 million accrued for remediation of the site as of December 31, 2018 included in Other deferred credits and other liabilities on our Consolidated Balance Sheets. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

For additional information on environmental matters, see Item 1 in this Annual Report on Form 10-K.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the consolidated financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

(20) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds and a contract performance guarantee.

We had the following guarantees in place as of (in thousands):

Nature of Guarantee	Maximum Exposure at December 31, 2018		Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$	54,683	Ongoing
Contract performance guarantee [(b)]		39,807	December 2019
	$	94,490	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

(b) BHC has guaranteed the full and complete payment and performance on behalf of Black Hills Electric Generation for construction of the Busch Ranch II Wind Farm. The guarantee terminates when BHC or Black Hills Electric Generation has paid for and performed all guaranteed obligations. The guarantee decreases as progress payments are made.

(21) DISCONTINUED OPERATIONS

Results of operations for discontinued operations have been classified as Net (loss) from discontinued operations in the accompanying Consolidated Statements of Income. Current assets and current liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as “Current assets held for sale” and “Current liabilities held for sale”, respectively. Prior periods relating to our discontinued operations have also been reclassified to reflect consistency within our consolidated financial statements.

<u>Oil and Gas Segment</u>

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of December 31, 2018, we have sold our oil and gas properties and completed the exit of the Oil and Gas business.

In 2017, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The market approach was based on our fourth quarter 2017 sale of our Powder River Basin assets and pending sale transactions of our other properties. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale were reasonable based on the information that was known when the estimates were made. At December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required an after-tax write down of $13 million. There were no adjustments made to the fair value of our held for sale liabilities.

For the year ended December 31, 2018, we recorded $3.3 million of expenses comprised of royalty payments and reclamation costs related to final closing on the sale of BHEP assets.

Total assets and liabilities of BHEP at December 31, 2017 were classified as Current assets held for sale and Current liabilities held for sale on the accompanying Consolidated Balance Sheets due to the final disposals occurring in 2018.

(in thousands)	As of December 31, 2017	
Other current assets	$	10,360
Deferred income tax assets, noncurrent, net		16,966
Property, plant and equipment, net		56,916
Other current liabilities		(18,966)
Other noncurrent liabilities		(22,808)
Net assets	$	42,468

At December 31, 2017, the Oil and Gas segment's net deferred tax assets were primarily comprised of basis differences on oil and gas properties.

BHEP's Other current liabilities at December 31, 2017 consisted primarily of accrued royalties, payroll and property taxes. Other noncurrent liabilities at December 31, 2017 consisted primarily of ARO obligations relating to plugging and abandonment of oil and gas wells.

Operating results of the Oil and Gas segment included in Discontinued operations on the accompanying Consolidated Statements of Income were as follows (in thousands):

	For the Years Ended		
	December 31, 2018	December 31, 2017	December 31, 2016
Revenue	$ 5,897	$ 25,382	$ 34,058
Operations and maintenance	11,014	22,872	27,187
Loss on sale of assets	3,259	—	—
Depreciation, depletion and amortization	1,300	7,521	13,510
Impairment of long-lived assets	—	20,385	106,957
Total operating expenses	15,573	50,778	147,654
Operating (loss)	(9,676)	(25,396)	(113,596)
Interest income (expense), net	(19)	181	698
Other income (expense), net	190	(297)	110
Income tax benefit	2,618	8,413	48,626
(Loss) from discontinued operations	$ (6,887)	$ (17,099)	$ (64,162)

Full Cost Accounting

Historically, we used the full cost method of accounting for oil and gas production activities. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated reclamation and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are typically treated as adjustments to the cost of the properties with no gain or loss recognized.

Costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized.

Under the full cost method, net capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC, plus the lower of cost or market value of unevaluated properties. Future net cash flows are estimated based on SEC-defined end-of-period commodity prices adjusted for contracted price changes and held constant for the life of the reserves. An average price is calculated using the price at the first day of each month for each of the preceding 12 months. If the net capitalized costs exceed the full cost "ceiling" at period end, a permanent non-cash write-down would be charged to earnings in that period.

Impairment of long-lived assets

As discussed above, at December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required a write down of $20 million. There were no adjustments made to the fair value of our held for sale liabilities.

As a result of continued low commodity prices throughout 2016, we recorded non-cash ceiling test impairments of our Oil and Gas assets totaling approximately $92 million for the year ended December 31, 2016. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $2.48 per Mcf, adjusted to $2.25 per Mcf at the wellhead; for crude oil, the average NYMEX price was $42.75 per barrel, adjusted to $37.35 per barrel at the wellhead.

During the second quarter of 2016, certain non-core assets were identified that were not suitable for inclusion in a possible Cost of Service Gas Program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of $14 million, in addition to the ceiling test impairments noted above.

(22) OIL AND GAS RESERVES (Unaudited)

On November 1, 2017, we initiated the process of divesting all Oil and Gas segment assets in order to fully exit the oil and gas business. On November 1, 2017, we stopped the use of the full-cost method of accounting for our oil and gas business. The assets and liabilities have been classified as held for sale and the results of operations are included in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. As a result, our oil and gas reserves were no longer considered significant in 2017. Oil and Gas reserves were considered significant in 2016. For more information, see Note 21.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31 (in thousands):

	2016
Acquisition of properties:	
Proved	$ —
Unproved	910
Exploration costs	1,102
Development costs	4,657
Asset retirement obligations incurred	—
Total costs incurred	$ 6,669

Reserves

The following table summarizes BHEP’s quantities of proved developed and undeveloped oil, natural gas and NGL reserves, estimated using SEC-defined product prices, as of December 31, 2016 and a reconciliation of the changes. The summary information presented for our estimated proved developed and undeveloped crude oil, natural gas, and NGL reserves and the 10% discounted present value of estimated future net revenues is based on reports prepared by Cawley Gillespie & Associates (CG&A), an independent consulting and engineering firm located in Fort Worth, Texas. CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Evaluation Engineers (SPEE), and has over 31 years of practical experience in petroleum engineering and over 29 years of experience in the estimation and evaluation of reserves. Reserves were determined consistent with SEC requirements using a 12-month average product price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Reserves for crude oil, natural gas, and NGLs are reported separately and then combined for a total MMcfe (where oil and NGLs in Mbbl are converted to an MMcfe basis by multiplying Mbbl by six). Such reserve estimates were inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

Minor differences in amounts may result in the following tables relating to oil and gas reserves due to rounding.

	2016		
	Oil	Gas	NGL
	(in Mbbls of oil and NGL, and MMcf of gas)		
Proved developed and undeveloped reserves:			
Balance at beginning of year	3,450	73,412	1,752
Production [(a)]	(319)	(9,430)	(133)
Sales	(570)	(1,291)	(17)
Additions - extensions and discoveries	3	52	—
Revisions to previous estimates	(322)	(8,173)	110
Balance at end of year	2,242	54,570	1,712
Proved developed reserves at end of year included above	2,242	54,570	1,712
Proved undeveloped reserves at the end of year included in above	—	—	—
NYMEX prices	$ 42.75	$ 2.48	$ —
Well-head reserve prices[(c)]	$ 37.35	$ 2.25	$ 11.92

(a) Production for reserve calculations did not include volumes for natural gas liquids (NGLs) for historical periods.

(b) A specific NYMEX price for NGL was not available. Market prices for NGL are broken down by various liquid components, including ethane, propane, isobutane, normal butane, and natural gasoline. Each of these components is traded as an index. Ethane was not being recovered at any of the facilities that process our natural gas production.

(c) For reserves purposes, costs to gather gas previously netted from the gas price were reclassified into operating expenses in 2016, with approximate rates of $1.54/Mcf for Piceance, $0.92/Mcf for San Juan and $0.53/Mcf for all others. The sales price for natural gas was adjusted for transportation costs and other related deductions when applicable.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31 (in thousands):

	2016
Unproved oil and gas properties	$ 18,547
Proved oil and gas properties	1,043,558
Gross capitalized costs	1,062,105
Accumulated depreciation, depletion and amortization and valuation allowances	(1,000,091)
Net capitalized costs	$ 62,014

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Results of Operations

For more on oil and gas producing activities included in discontinued operations, see Note 21. Following is a summary of results of operations for producing activities for the years ended December 31 (in thousands):

		2016
Revenue	$	34,058
Production costs		17,231
Depreciation, depletion and amortization		12,574
Impairment of long-lived assets		106,957
Total costs		136,762
Results of operations from producing activities before tax		(102,704)
Income tax benefit (expense)		37,916
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$	(64,788)

Unproved Properties

Unproved properties not subject to amortization at December 31, 2016 consisted mainly of exploration costs on various existing work-in-progress projects as well as leasehold acquired through significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $0.9 million of interest during 2016 on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2016 and notes the year in which the associated costs were incurred (in thousands):

		2016
Leasehold acquisition cost	$	963
Exploration cost		532
Capitalized interest		50
Total	$	1,545

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure of discounted future net cash flows and changes relating to proved oil and gas reserves for the years ended December 31 (in thousands):

		2016
Future cash inflows	$	246,221
Future production costs		(166,248)
Future development costs, including plugging and abandonment		(18,333)
Future net cash flows		61,640
10% annual discount for estimated timing of cash flows		(26,574)
Standardized measure of discounted future net cash flows	$	35,066

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31 (in thousands):

	2016
Standardized measure - beginning of year	$ 79,028
Sales and transfers of oil and gas produced, net of production costs	(4,314)
Net changes in prices and production costs	(32,698)
Changes in future development costs	1,825
Revisions of previous quantity estimates	(7,477)
Accretion of discount	7,903
Sales of reserves	(9,201)
Standardized measure - end of year	$ 35,066

Changes in the standardized measure from "revisions of previous quantity estimates" were driven by reserve revisions, modifications of production profiles and timing of future development. For all years presented, we had minimal net reserve revisions to prior estimates due to performance. Production forecast modifications were generally made at the well level each year through the reserve review process. These production profile modifications were based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments were reviewed each year and were often modified in response to current market conditions for items such as permitting and service availability.

(23) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth select unaudited historical operating results and market data for each quarter of 2018 and 2017.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2018				
Revenue	$ 575,389	$ 355,704	$ 321,979	$ 501,196
Operating income (loss)	$ 148,274	$ 69,551	$ 65,085	$ 114,127
Income (loss) from continuing operations	$ 138,977	$ 27,167	$ 21,801	$ 91,604
Income (loss) from discontinued operations	$ (2,343)	$ (2,427)	$ (857)	$ (1,260)
Net income attributable to noncontrolling interest	$ (3,630)	$ (2,823)	$ (3,994)	$ (3,773)
Net income (loss) available for common stock	$ 133,004	$ 21,917	$ 16,950	$ 86,571
Amounts attributable to common shareholders:				
Net income (loss) from continuing operations	$ 135,347	$ 24,344	$ 17,807	$ 87,831
Net income (loss) from discontinued operations	$ (2,343)	$ (2,427)	$ (857)	$ (1,260)
Net income (loss) available for common stock	$ 133,004	$ 21,917	$ 16,950	$ 86,571
Income (loss) per share for continuing operations - Basic	$ 2.54	$ 0.46	$ 0.33	$ 1.52
Income (loss) per share for discontinued operations - Basic	$ (0.05)	$ (0.05)	$ (0.02)	$ (0.02)
Earnings (loss) per share - Basic	$ 2.49	$ 0.41	$ 0.32	$ 1.50
Income (loss) per share for continuing operations - Diluted	$ 2.50	$ 0.45	$ 0.32	$ 1.51
Income (loss) per share for discontinued operations - Diluted	$ (0.04)	$ (0.05)	$ (0.02)	$ (0.02)
Earnings (loss) per share - Diluted	2.46	0.40	0.31	1.49

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Included within the Income (loss) from continuing operations in the first and fourth quarters of 2018 are tax benefits of $49 million and $23 million, respectively, related to goodwill that is amortizable for tax purposes which resulted from legal entity restructuring.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2017				
Revenue	$ 547,528	$ 341,829	$ 335,611	$ 455,298
Operating income (loss)	$ 150,186	$ 69,796	$ 79,559	$ 117,195
Income (loss) from continuing operations	$ 81,715	$ 25,927	$ 32,898	$ 67,835
Income (loss) from discontinued operations	$ (1,569)	$ (616)	$ (1,300)	$ (13,614)
Net income attributable to noncontrolling interest	$ (3,623)	$ (3,116)	$ (3,935)	$ (3,568)
Net income (loss) available for common stock	$ 76,523	$ 22,195	$ 27,663	$ 50,653
Amounts attributable to common shareholders:				
Net income (loss) from continuing operations	78,092	22,811	28,963	64,267
Net income (loss) from discontinued operations	(1,569)	(616)	(1,300)	(13,614)
Net income (loss) available for common stock	76,523	22,195	27,663	50,653
Income (loss) per share for continuing operations - Basic	$ 1.47	$ 0.43	$ 0.54	$ 1.21
Income (loss) per share for discontinued operations - Basic	(0.03)	(0.01)	(0.02)	(0.26)
Earnings (loss) per share - Basic	$ 1.44	$ 0.42	$ 0.52	$ 0.95
Income (loss) per share for continuing operations - Diluted	$ 1.42	$ 0.41	$ 0.52	$ 1.17
Income (loss) per share for discontinued operations - Diluted	(0.03)	(0.01)	(0.02)	(0.25)
Earnings (loss) per share - Diluted	$ 1.39	$ 0.40	$ 0.50	$ 0.92

Income from continuing operations for each quarter of 2017 included external incremental acquisition and transaction costs. We incurred after-tax external incremental acquisition and transaction expenses of $0.9 million during the first quarter, $0.3 million during the second quarter, $0.2 million during the third quarter and $1.3 million during the fourth quarter.

Included within the Income (loss) from continuing operations in the fourth quarter of 2017 is a net tax benefit of $7.6 million from the impact of the TCJA, as well as a tax benefit of $4.1 million from a true-up to the filed 2016 SourceGas tax returns related to the SourceGas acquisition.

Included within the Loss from discontinued operations in the fourth quarter of 2017 is an after-tax non-cash impairment of oil and gas properties of $13 million.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2018. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2018, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting is presented on Page 86 of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407 (d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2019 Annual Meeting of Shareholders, which is incorporated herein by reference.

Executive Officers

David R. Emery, age 56, has been Executive Chairman since January 1, 2019, Chairman and Chief Executive Officer from 2016 through 2018, and Chairman, President and Chief Executive Officer from 2005 through 2015. Prior to that, he held various positions with the Company, including President and Chief Executive Officer and member of the Board of Directors from 2004 to 2005, President and Chief Operating Officer — Retail Business Segment from 2003 to 2004 and Vice President — Fuel Resources from 1997 to 2003. Mr. Emery has 29 years of experience with the Company.

Linden R. Evans, age 56, has been President and Chief Executive Officer since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer — Utilities from 2004 through 2015. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and Associate Counsel from 2001 to 2003. Mr. Evans has 17 years of experience with the Company.

Scott A. Buchholz, age 57, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 38 years of experience with the Company, including 28 years with Aquila.

Brian G. Iverson, age 56, has been Senior Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary since February 1, 2019. He served as Senior Vice President, General Counsel and Chief Compliance Officer from 2016 to February 2019, Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to 2016, Vice President and Treasurer from 2011 to 2014, Vice President - Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 15 years of experience with the Company.

Richard W. Kinzley, age 53, has been Senior Vice President and Chief Financial Officer since 2015. He served as Vice President - Corporate Controller from 2013 to 2014, Vice President - Strategic Planning and Development from 2008 to 2013, and as Director of Corporate Development from 2000 to 2008. Mr. Kinzley has 19 years of experience with the Company.

Jennifer C. Landis, age 44, has been Senior Vice President - Chief Human Resources Officer since February 1, 2017. She served as Vice President of Human Resources from April 2016 through January 2017, Director of Corporate Human Resources and Talent Management from 2013 to April 2016, and Director of Organization Development from 2008 to 2013. Ms. Landis has 17 years of experience with the Company.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2019 Annual Meeting of Shareholders, which is incorporated herein by reference.

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

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2019 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2018 with respect to our equity compensation plans. These plans include the 2005 Omnibus Incentive Plan and 2015 Omnibus Incentive Plan.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	256,111 (1)	$ 41.63 (1)	800,180 (2)
Equity compensation plans not approved by security holders	—	$ —	—
Total	256,111	$ 41.63	800,180

(1) Includes 187,362 full value awards outstanding as of December 31, 2018, comprised of restricted stock units, performance shares, short-term incentive plan (STIP) units and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares, STIP or common stock units. In addition, 235,748 shares of unvested restricted stock were outstanding as of December 31, 2018, which are not included in the above table because they have already been issued.

(2) Shares available for issuance are from the 2015 Omnibus Incentive Plan. The 2015 Omnibus Incentive Plan permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock based awards.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2019 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2019 Annual Meeting to Shareholders, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II

2. Schedules

Schedule II — Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2018, 2017 and 2016

3. Exhibits

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

SCHEDULE II

Consolidated valuation and qualifying accounts are detailed within Note 1 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

3. Exhibits

Exhibit Number	Description
2.1*	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015).
2.2*	First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 10-K for 2015).
2.3*	Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018).
3.2*	Amended and Restated Bylaws of the Registrant dated April 24, 2017 (filed as Exhibit 3 to the Registrant's Form 8-K filed on April 28, 2017).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009).

Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010).

Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013).

Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016).

Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016).

Seventh Supplemental Indenture dated as of August 17, 2018 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2018).

4.2* Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).

First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).

Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)).

Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).

4.3* Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014).

First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014).

Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).

4.4* Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).

10.1*† Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001).

First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002).

Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).

10.2*† 2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).

10.3*† Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008).

First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).

10.4*† Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).

10.5† First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011.

10.6† Black Hills Corporation Post-2018 Nonqualified Deferred Compensation Plan.

10.7*†	Black Hills Corporation 2005 Omnibus Incentive Plan (”Omnibus Plan”) (filed as Appendix A to the Registrant’s Proxy Statement filed April 13, 2005).
	First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant’s Form 10-K for 2008).
	Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant’s Form 8-K filed on May 26, 2010).
10.8*†	Black Hills Corporation 2015 Omnibus Incentive Plan (filed as Appendix B to the Registrant’s Proxy Statement filed March 19, 2015).
10.9*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant’s Form 10-K for 2013).
	Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant’s Form 10-K for 2015).
10.10*†	Form of Restricted Stock Award Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant’s Form 10-K for 2015).
10.11*†	Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant’s Form 10-K for 2015).
10.12*†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant’s Form 10-Q for the quarterly period ended March 31, 2016).
	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2017 (files as Exhibit 10 to the Registrant’s Form 10-Q for the quarterly period ended March 31, 2017).
10.13*†	Form of Short-term Incentive effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.7 to the Registrant’s Form 10-Q for the quarterly period ended March 31, 2016).
10.14*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant’s Form 8-K filed on September 3, 2004).
10.15*†	Change in Control Agreement dated November 15, 2016 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on November 16, 2016).
10.16*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on November 16, 2016).
10.17*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant’s Form 10-K for 2008).
	First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant’s Form 10-K for 2010).
	Second Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant’s Form 10-K for 2012).
	Third Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2015 (filed as Exhibit 10.16 to the Registrant’s Form 10-K for 2014).
	Fourth Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2017 (filed as Exhibit 10.4 to the Registrant’s Form 10-Q for the quarterly period ended September 30, 2016).
	Fifth Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2018 (filed as Exhibit 10.16 to the Registrant’s Form 10-K for 2017).
10.18†	Sixth Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2019.
10.19*†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.8 to the Registrant’s Form 10-Q for the quarterly period ended March 31, 2016).

10.20*	Equity Distribution Sales Agreement dated August 4, 2017 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on August 4, 2017).
10.21*	Third Amended and Restated Credit Agreement dated as of July 30, 2018 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 31, 2018).
10.22*	Amended and Restated Credit Agreement dated as of July 30, 2018 (relating to $300 million, two-year term loan), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 31, 2018).
10.23*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.24*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data
101	Financial Statements in XBRL Format

* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

BLACK HILLS CORPORATION

By: /S/ LINDEN R. EVANS
Linden R. Evans, President and Chief Executive Officer

Dated: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ LINDEN R. EVANS Linden R. Evans, President and Chief Executive Officer	Director and Principal Executive Officer	February 19, 2019
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 19, 2019
/S/ DAVID R. EMERY David R. Emery, Executive Chairman	Director and Executive Chairman	February 19, 2019
/S/ MICHAEL H. MADISON Michael H. Madison	Director	February 19, 2019
/S/ STEVEN R. MILLS Steven R. Mills	Director	February 19, 2019
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 19, 2019
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 19, 2019
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 19, 2019
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 19, 2019
/S/ JOHN B. VERING John B. Vering	Director	February 19, 2019
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 19, 2019

FORM 10K

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Use of Non-GAAP Financial Measures

Earnings Per Share, as adjusted (Non-GAAP Measure)	Year Ended Dec. 31 2018	2017	2016	2015	2014	2013
Income from continuing operations available for common stock (GAAP)	**$ 4.78**	**$ 3.52**	**$ 2.57**	**$ 3.12**	**$ 2.97**	**$ 2.55**
Adjustments (loss) (*pre-tax*):						
Interest rate swaps - MTM	-	-	-	-	-	(0.68)
Costs associated with prepayment of BHW project financing (Net of interest savings)	-	-	-	-	-	0.23
Financing costs, net of interest savings ($250M bond payoff)	-	-	-	-	-	0.20
Integration expenses	-	0.08	0.86	0.23	-	-
Tax reform and other tax items	0.07	(0.21)	-	-	-	-
Legal restructuring - income tax benefit	(1.31)	-	-	-	-	-
Total Adjustments	(1.24)	(0.13)	0.86	0.23	-	(0.25)
Taxes on Adjustments:						
Interest rate swaps - MTM	-	-	-	-	-	0.24
Costs associated with prepayment of BHW project financing (Net of interest savings)	-	-	-	-	-	(0.08)
Financing costs, net of interest savings ($250M bond payoff)	-	-	-	-	-	(0.07)
Acquisition costs	-	(0.03)	(0.30)	(0.08)	-	-
Total tax on adjustments	-	(0.03)	(0.30)	(0.08)	-	0.09
Earnings Per Share from continuing operations available for common stock, as adjusted (Non-GAAP)	**$ 3.54**	**$ 3.36**	**$ 3.13**	**$ 3.27**	**$ 2.97**	**$ 2.39**

* 8.2 percent compound annual growth rate in earnings per share from continuing operations available for common stock, as adjusted, from 2013 to 2018

EBITDA, as adjusted (Non-GAAP Measure, in millions)	Year Ended Dec. 31 2018	2017	2016	2015	2014	2013
Income from continuing operations (GAAP)	**$ 279.5**	**$ 208.4**	**$ 146.8**	**$ 141.5**	**$ 132.5**	**$ 113.3**
Depreciation, depletion and amortization	196.3	188.2	175.5	126.5	121.0	120.2
Interest expense, net	140.0	137.1	134.7	83.0	69.9	111.9
Unrealized gain on interest rate swaps, net	-	-	-	-	-	(30.2)
Income tax expense	(23.7)	73.4	59.1	78.7	67.3	61.2
Rounding	0.1	(0.1)	-	0.1	(0.1)	-
EBITDA (Non-GAAP Measure)	**592.2**	**607.0**	**516.1**	**429.8**	**390.6**	**376.4**
Less: Adjustments for unique items						
Acquisition costs	-	4.4	43.7	3.6	-	-
EBITDA, as adjusted (Non-GAAP Measure)	**$ 592.2**	**$ 611.4**	**$ 559.8**	**$ 433.4**	**$ 390.6**	**$ 376.4**

* 9.5 percent compound annual growth rate in EBITDA, as adjusted, from 2013 to 2018

NON-GAAP

Earnings per share, as adjusted

Earnings per share, as adjusted, is a Non-GAAP financial measure. Earnings per share, as adjusted, is defined as GAAP Earnings per share, adjusted for expenses, gains and losses that the Company believes do not reflect the Company's core operating performance. Examples of these types of adjustments may include unique one-time non-budgeted events, impairment of assets, acquisition and disposition costs, and other adjustments noted in the earnings reconciliation tables in this presentation.

EBITDA and EBITDA, as adjusted

We believe that our presentation of earnings before interest, income taxes, depreciation and amortization (EBITDA) and EBITDA, as adjusted (EBITDA adjusted for special items as defined by management), both non-GAAP measures, are important supplemental measures of operating performance. We believe EBITDA and EBITDA, as adjusted, when considered with measures calculated in accordance with GAAP, give investors a more complete understanding of operating results before the impact of investing and financing transactions and income taxes. We have chosen to provide this information to investors to enable them to perform more meaningful comparisons of past and present operating results and as a means to evaluate the results of core on-going operations.

Limitations on the Use of Non-GAAP Measures

Non-GAAP measures have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our presentation of these non-GAAP financial measures should not be construed as an inference that our future results will not be affected by unusual, non-routine, or non-recurring items.

Non-GAAP measures should be used in addition to and in conjunction with results presented in accordance with GAAP. Non-GAAP measures should not be considered as an alternative to net income, operating income or any other operating performance measure prescribed by GAAP, nor should these measures be relied upon to the exclusion of GAAP financial measures. Our non-GAAP measures reflect an additional way of viewing our operations that we believe, when viewed with our GAAP results and the reconciliation to the corresponding GAAP financial measures, provide a more complete understanding of factors and trends affecting our business than could be obtained absent this disclosure. Management strongly encourages investors to review our financial information in its entirety and not rely on a single financial measure.

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BOARD OF DIRECTORS

David R. Emery, age 56, was elected to the Board in 2004. He has been Executive Chairman since January 1, 2019, was our Chairman and CEO from 2016 through 2018, and Chairman, President and CEO from 2005 through 2015. Prior to that he held various positions with the Company, including President and Chief Executive Officer from 2004 to 2005, President and COO — Retail Business Segment from 2003 to 2004, and Vice President—Fuel Resources from 1997 to 2003.

Linden R. Evans, age 56, was elected to the Board in November 2018. He has been President and Chief Executive Officer since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer — Utilities from 2004 through 2015. Prior to that he served as the Vice President and General Manager of our former telecommunications subsidiary in 2003 and 2004, and Associate Counsel from 2001 to 2003.

Michael H. Madison, age 70, was elected to the Board in 2012 and chairs the Compensation Committee. He was President, CEO and a Director of Cleco Corp., a public utility holding company, from 2005 to 2011, President and COO of Cleco Power, LLC from 2003 to 2005, and State President, Louisiana-Arkansas with American Electric Power from 2000 to 2003.

Steven R. Mills, age 63, was elected to the Board in 2011 and chairs the Audit Committee. He has been a Financial Consultant and Advisor in the private equity, agribusiness, renewable products and financial services fields since 2013. He previously served as CFO of Amyris, Inc., an integrated renewable products company, from 2012 to 2013. Prior to that, he held several executive positions, including Senior Executive Vice President Performance and Growth and CFO at Archer Daniels Midland Co., a processor, transporter, buyer and marketer of agricultural products. He also serves on the Board of Amyris, Inc.

Robert P. Otto, age 59, was elected to the Board in 2017. He has been the owner of Bob Otto Consulting LLC, providing strategic planning and services in cyber security, intelligence and reconnaissance since 2017. He retired from the U.S. Air Force in 2016 as a lieutenant general. He served as a general officer since 2008, culminating as the Deputy Chief of Staff for Intelligence, Surveillance and Reconnaissance.

Rebecca B. Roberts, age 66, was elected to the Board in 2011 and chairs the Governance Committee. She was President of Chevron Pipe Line Co., a transporter of crude oil, refined petroleum products, liquefied petroleum gas, natural gas and chemicals within the U.S. from 2006 to 2011, and President of Chevron Global Power Generation from 2003 to 2006. She also serves on the Board of AbbVie, Inc. and MSA Safety, Inc.

Mark A. Schober, age 63, was elected to the Board in 2015. He was Senior Vice President and CFO of ALLETE, Inc., a public energy company, from 2006 to 2014. He previously held several positions in accounting and finance.

Teresa A. Taylor, age 55, was elected to the Board in 2016. She has been CEO of Blue Valley Advisors, LLC since 2011. She previously served as COO of Qwest Communications, Inc., a telecommunications carrier, from 2009 to 2011. She also served in other leadership roles at Qwest and the former U.S. West beginning in 1987, including Executive Vice President and Chief Administrative Officer. She also serves on the Board of T-Mobile USA, Inc. and First Interstate BancSystem, Inc.

John B. Vering, age 69, was elected to the Board in 2005 and serves as our Lead Director. He has been Managing Director of Lone Mountain Investments, Inc., an oil and gas investment firm, since 2002. He previously held several executive positions in the oil and gas industry.

Thomas J. Zeller, age 71, was elected to the Board in 1997. He was CEO of RESPEC, a technical consulting and services firm with expertise in engineering, information technologies and water and natural resources, specializing in emerging environmental protection protocols, in 2011, and served as President from 1995 to 2011.

EXECUTIVE OFFICERS

David R. Emery, age 56, has been Executive Chairman since January 1, 2019, Chairman and Chief Executive Officer from 2016 through 2018, and Chairman, President and Chief Executive Officer from 2005 through 2015. Prior to that, he held various positions with the Company, including President and Chief Executive Officer and member of the Board of Directors from 2004 to 2005, President and Chief Operating Officer — Retail Business Segment from 2003 to 2004 and Vice President — Fuel Resources from 1997 to 2003. Mr. Emery has 29 years of experience with the Company.

Linden R. Evans, age 56, has been President and Chief Executive Officer since January 1, 2019, President and Chief Operating Officer from 2016 through 2018, and President and Chief Operating Officer — Utilities from 2004 through 2015. Mr. Evans served as the Vice President and General Manager of our former telecommunications subsidiary in 2003 and 2004, and served as our Associate Counsel from 2001 to 2003. Mr. Evans has 17 years of experience with the Company.

Scott A. Buchholz, age 57, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 38 years of experience with the Company, including 28 years with Aquila.

Brian G. Iverson, age 56, has been Senior Vice President, General Counsel, Chief Compliance Officer and Corporate Secretary since February 1, 2019. He served as Senior Vice President, General Counsel and Chief Compliance Officer from 2016 to February 2019, Senior Vice President — Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to 2016, Vice President and Treasurer from 2011 to 2014, Vice President — Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 15 years of experience with the Company.

Richard W. Kinzley, age 53, has been Senior Vice President and Chief Financial Officer since January 2015. He served as Vice President — Corporate Controller from 2013 to 2014, Vice President — Strategic Planning and Development from 2008 to 2013, and as Director of Corporate Development from 2000 to 2008. Mr. Kinzley has 19 years of experience with the Company.

Jennifer C. Landis, age 44, has been Senior Vice President — Chief Human Resources Officer since February 1, 2017. She served as Vice President of Human Resources from April 2016 through January 2017, Director of Corporate Human Resources and Talent Management from 2013 to April 2016, and Director of Organization Development from 2008 to 2013. Ms. Landis has 17 years of experience with the Company.

INVESTOR INFORMATION

COMMON STOCK
Transfer Agent, Registrar & Dividend Disbursing Agent
EQ Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
800-468-9716
www.shareowneronline.com

SENIOR UNSECURED NOTES — BLACK HILLS CORPORATION
Wells Fargo Bank, N.A.
Corporate Trust Services
MAC N9300-070
600 S. 4th Street, 6th Floor
Minneapolis, MN 55415

FIRST MORTGAGE BONDS — BLACK HILLS POWER, INC.
The Bank of New York Mellon
Corporate Trust Services, CF
101 Barclay Street, 7W
New York, NY 10286

FIRST MORTGAGE BONDS — CHEYENNE LIGHT, FUEL & POWER
Wells Fargo Bank, N.A.
Corporate Trust Services
MAC N9300-070
600 S. 4th Street, 6th Floor
Minneapolis, MN 55415

ENVIRONMENTAL IMPROVEMENT REVENUE BONDS — BLACK HILLS POWER, INC.
Trustee & Paying Agent
The Bank of New York Mellon
100 Pine Street, Suite 3150
San Francisco, CA 94111

INDUSTRIAL DEVELOPMENT REVENUE BONDS — CHEYENNE LIGHT, FUEL & POWER
Trustee & Paying Agent
Corporate Trust Services
US Bank National Association
EP-MN-WN3L
60 Livingston Avenue
St. Paul, MN 55107

CORPORATE OFFICES

Black Hills Corporation
P.O. Box 1400
7001 Mount Rushmore Road
Rapid City, SD 57702
605-721-1700
www.blackhillscorp.com

2019 ANNUAL MEETING

The Annual Meeting of Shareholders will be held at Horizon Point, the Company's corporate headquarters at 7001 Mount Rushmore Road, Rapid City, South Dakota, at 9:30 a.m. local time on Tuesday, April 30, 2019. Prior to the meeting, formal notice, proxy statement and proxy will be mailed to shareholders.

MARKET FOR EQUITY SECURITIES

The Company's Common Stock ($1 par value) is traded on the New York Stock Exchange. Quotations for the Common Stock are reported under the symbol BKH. The continued interest and support of equity owners are appreciated. The Company has declared Common Stock dividends payable in each year since its incorporation in 1941. Regular quarterly dividends when declared are normally payable on March 1, June 1, September 1 and December 1.

INTERNET ACCOUNT ACCESS

Registered shareholders can access their accounts electronically at www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and much more. The transfer agent maintains stockholder account access.

DIRECT DEPOSIT OF DIVIDENDS

We encourage you to consider the direct deposit of your dividends. With direct deposit, your quarterly dividend payment can be automatically transferred on the dividend payment date to the bank, savings and loan, or credit union of your choice. Direct deposit assures payments are credited to shareholders' accounts without delay. A form is attached to your dividend check where you can request information about this method of payment. Questions regarding direct deposit should be directed to EQ Shareowner Services.

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

A Dividend Reinvestment and Direct Stock Purchase Plan provides interested investors the opportunity to purchase shares of the Company's Common Stock and to reinvest all or a percentage of their dividends. For complete details, including enrollment, contact the transfer agent, EQ Shareowner Services.

Plan information is also available at www.shareowneronline.com.

WEBSITE ACCESS TO REPORTS

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officer, Corporate Governance Guidelines of our Board of Directors, and Policy for Director Independence.

Black Hills Corporation

Ready

READY TO SERVE

At daybreak, across the hundreds of small towns and communities we call home, our employees like Cody and Mike, work together to ensure our customers have the safe, reliable energy they need and expect.

BKH 2018 | Black Hills Corporation | **Annual Report** | Proxy Statement | Form 10-K

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