

2018 Integrated Resource Plan (2019-2028)

NOVEMBER 2018

BASIN ELECTRIC POWER COOPERATIVE

SUBMITTED TO THE WESTERN AREA POWER ADMINISTRATION

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1) Executive Summary

The 2018 Integrated Resource Plan (2018 IRP) provides an in depth look at Basin Electric Power Cooperative's (Basin Electric) current operating system, future load growth and the framework for future expansion, including both supply-side and demand-side resource expansion. This Plan covers the period 2019-2028, presents a long-term view of Basin Electric's system needs, documents the analytical approach that Basin Electric uses for new resource justification and defines a five year action plan to most effectively meet growing member needs.

General

Basin Electric is a regional wholesale electric generation and transmission cooperative owned and controlled by the member cooperatives it serves. These cooperatives began operation in the 1940s and early 1950s as a result of Franklin D. Roosevelt's 1935 executive order establishing the Rural Electrification Administration (REA). At that time only 3.5 percent of the rural people of the Great Plains received central station electricity. The establishment of the REA made it possible for cooperatives to receive assistance in electrifying rural America where there were only one or two farms per mile of line. Prior to REA, electricity was not generally available in the rural areas, as investor-owned utilities had limited incentive to serve the low-density areas.

Today Basin Electric is the largest G&T cooperative in the nation in terms of land area served. As of April 2018, Basin Electric provides wholesale, supplemental electric service for 141 member cooperatives in the states of Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Approximately 3 million consumers are served by Basin Electric's member cooperative systems.

Resource Needs Assessment

Basin Electric forecasts peak demand on its system to grow by 660 MW from 2019 through 2028 or approximately 73 MW per year. Basin Electric forecasts energy consumption on its system to grow by approximately 4.3 million MWh from 2019 through 2028 or approximately 479,000 MWh per year. The load growth is driven mainly by commercial sector growth which includes energy related development in the form of oil and gas development and also increased loads in the residential sector mainly located on the outskirts of larger cities within the service territory.

The difference in the coincident peak demand forecast plus other obligations (such as non-member sales, losses, and reserves, less Basin Electric's system-wide load management) and existing and committed generating resources along with purchases, define the load and capability of the Basin Electric system which shows the amount that Basin Electric is either long or short capacity.

Since Basin Electric's member systems reside in four different assessment/planning areas on both the eastern and western interconnection and there is limited capability in moving power between the systems, Basin Electric further narrows its view on load and capability to these four assessment areas on both the eastern and western systems separately. The four assessment areas are: in the western interconnection there is the Northwest Power Pool (NWPP) and the Rocky Mountain Reserve Group (RMRG), and in the eastern interconnection there is the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP). In MISO, there is further segregation into 10 zones known as Local Resource Zones (LRZ), in which Basin Electric's members have loads in LRZ 1 and LRZ 3.

In the western interconnection Basin Electric has the rights to transfer up to 240 MW from the RMRG system across the Rapid City and Stegall DC Ties into the eastern interconnection into Basin Electric’s system in SPP. Because of how much surplus capacity Basin Electric has in the RMRG system, we plan to fully utilize those west to east transfer capabilities for the foreseeable future. Figure 1-1 shows Basin Electric’s RMRG system summer season surplus capacity both with and without the impacts from being able to transfer capacity across the Rapid City and Stegall DC Ties into SPP.

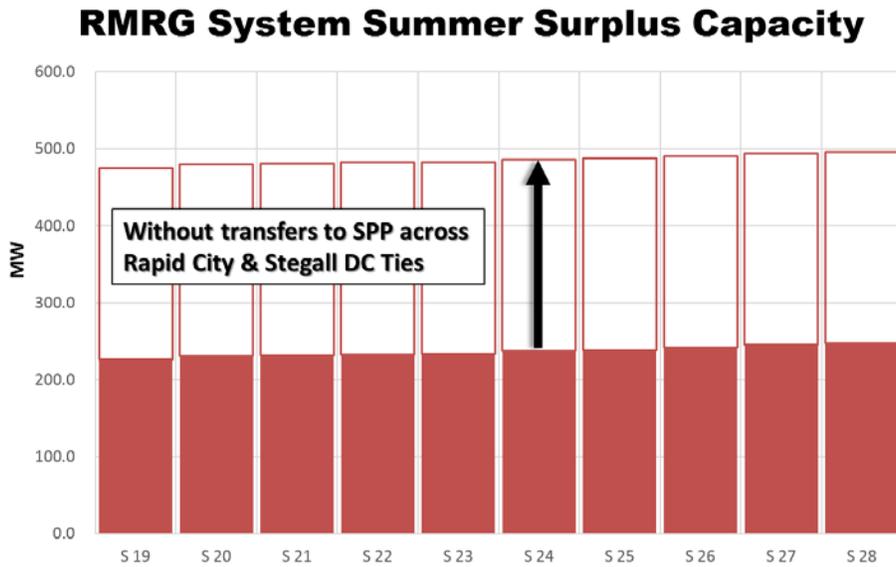


Figure 1-1 RMRG System Summer Surplus Capacity

Figure 1-2 shows Basin Electric’s NWPP system summer season surplus capacity. Basin Electric has the rights to transfer up to approximately 127 MW from the SPP system in the eastern interconnection across the Miles City DC tie into the NWPP system in the western interconnection. With the ability to transfer power east to west from SPP into NWPP, Basin Electric is not expecting to be deficit in NWPP until 2022 at which time approximately 50 MW of additional capacity would get us through 2025 or a little over 100 MW would get us through the study period.

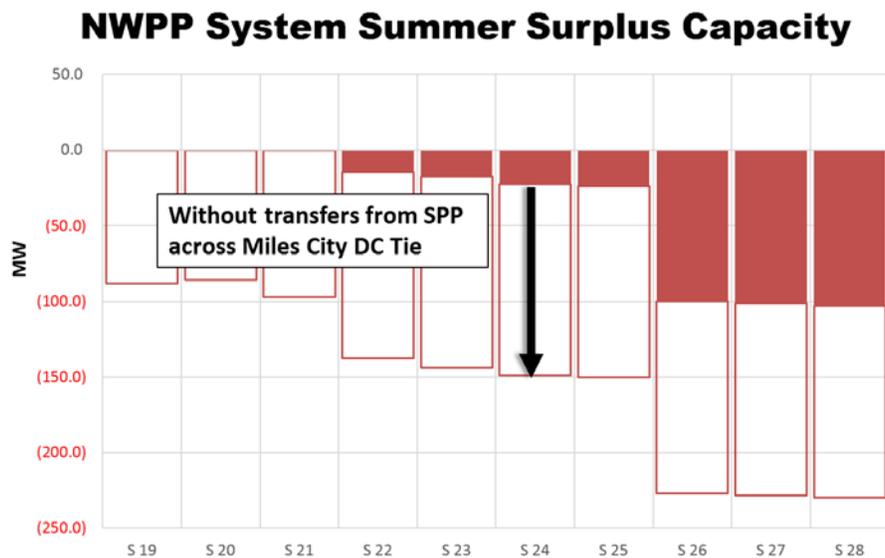


Figure 1-2 NWPP System Summer Surplus Capacity

Basin Electric’s Eastern System can be broken into SPP and MISO, where Basin Electric’s loads in MISO can be further broken down into LRZ 1 and LRZ 3. Figure 1-3 through Figure 1-5 shows Basin Electric’s systems in the Eastern Interconnection.

Figure 1-3 below shows Basin Electric’s MISO LRZ1 system summer season surplus capacity. Basin Electric’s MISO LRZ 1 system is shown to be deficit nearly 100 MW in 2023 and 2024 when some of our bilateral purchases in the region are expected to end and the deficit grows more substantial up to approximately 300 MW. This deficit is forecasted to grow more deficit year over year, to 332 MW by the end of the forecast period.

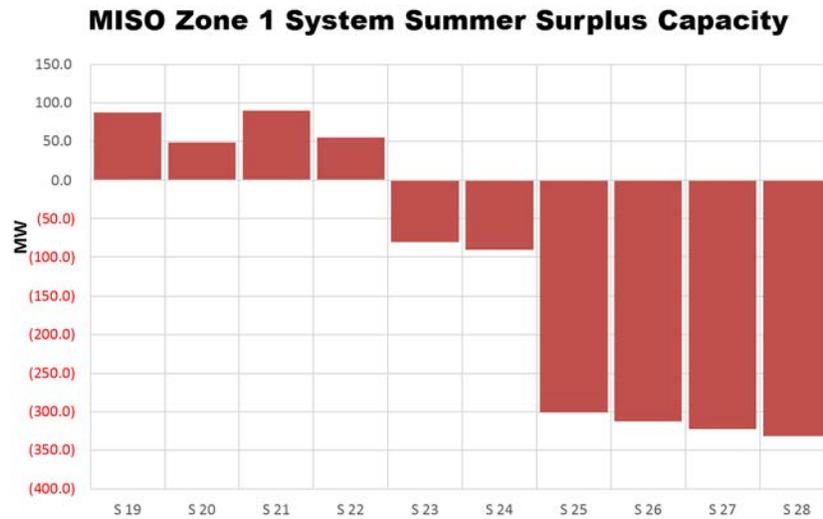


Figure 1-3 MISO LRZ 1 System Summer Surplus Capacity

Figure 1-4 shows Basin Electric’s MISO LRZ 3 system summer season surplus capacity. Basin Electric’s MISO LRZ 3 system is shown to not be deficit until 2026 when our MISO members are expected to gain additional obligations in the region. Basin Electric will continue to monitor the load forecasts and the impacts from these additional obligations.

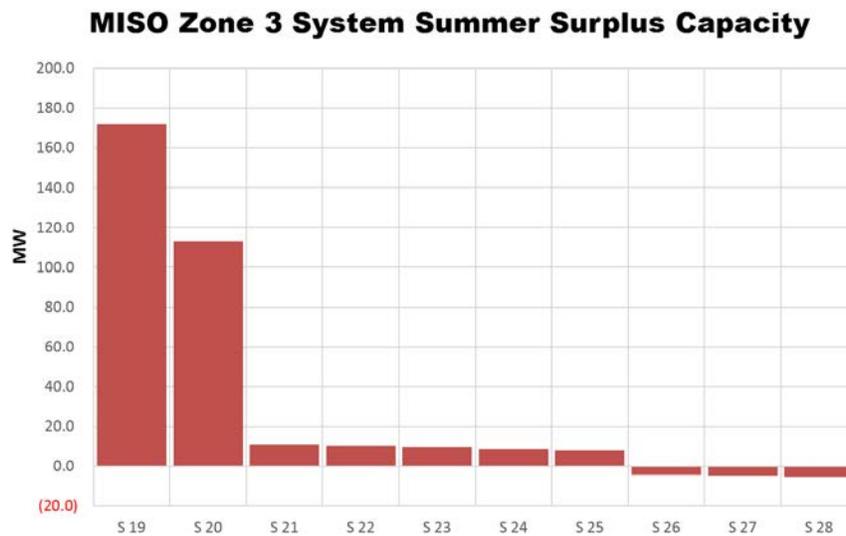


Figure 1-4 MISO LRZ 3 System Summer Surplus Capacity

Figure 1-5 shows Basin Electric’s SPP system. This is the portion of the eastern system showing the greatest growth over the forecasted period. This area encompasses the oil developing region known as the Williston Basin. This graph does include transfers across direct current (DC) ties; the Rapid City DC Tie and the Stegall DC Tie; to transfer power from the west to the east as well as supplying power to Basin Electric’s loads in NWPP across the Miles City DC Tie. The graph shows Basin Electric’s SPP system to be deficit around 200 MW in 2021. This deficit is forecasted to grow more deficit year over year, to more than 450 MW by 2023 and more than 825 MW by the end of the forecast period.

SPP System Summer Surplus Capacity

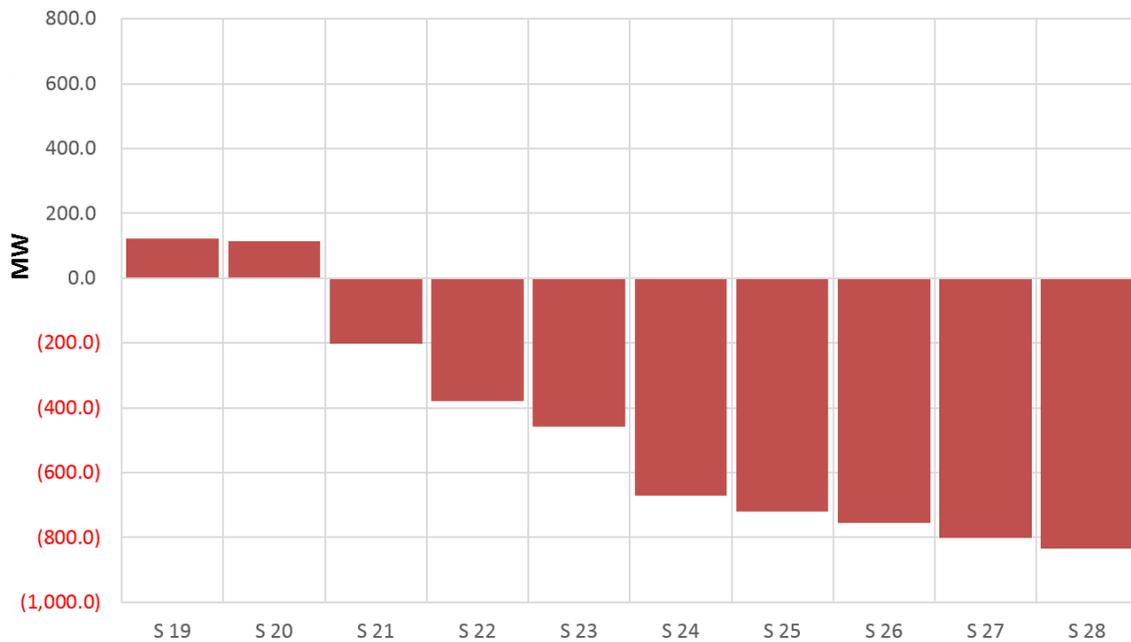


Figure 1-5 SPP System Summer Surplus Capacity

If the DC Tie transfers from the western interconnection to the eastern interconnection across the Rapid City and Stegall DC Ties are unavailable, or there is no surplus on the west to move east, Basin Electric’s SPP system would show up to an additional 240 MW deficit on top of what is shown in Figure 1-5.

Analytical Approach

Basin Electric’s analytical approach consists of multiple steps. First there is the development and approval of the member load forecast. Then Basin Electric’s power supply needs are reviewed.

Once it is determined when new power supply will be needed to meet forecasted member power obligations, market conditions in the various power supply regions needs to be assessed to see if neighboring utilities are expected to have excess power that they may be willing to sell at a market price. These prices for market power are compared to the cost of building new resources. Market prices for bilateral arrangements are determined by issuing a Request for Proposals (RFP) for power supply.

After we can determine if we can secure additional power supply through bilateral contracts with neighboring utilities at economically justifiable prices and know the duration in which that power supply can

be secured, we then utilize all of the above information as an input into the power supply model to determine the optimal long term power supply expansion alternatives outside of what we are able to secure through the RFP process if needed.

Conclusions

The 2018 IRP is intended to provide guidance and rationale for Basin Electric’s power supply options over the next several years. This section includes the major conclusions and recommendations from the 2018 IRP.

With the current coincident peak demand forecasts and Basin Electric’s power supply portfolio, including having made the decision not to extend the lease agreements with the owners of Antelope Valley Station Unit 2, there is a relatively near term need for capacity in a few of Basin Electric’s Power Supply Planning Regions. Based on this need, Basin Electric is recommending to move forward with the following bilateral purchases with neighboring utilities for their available surplus capacity.

Basin Electric’s Current Recommended Bilateral Purchases

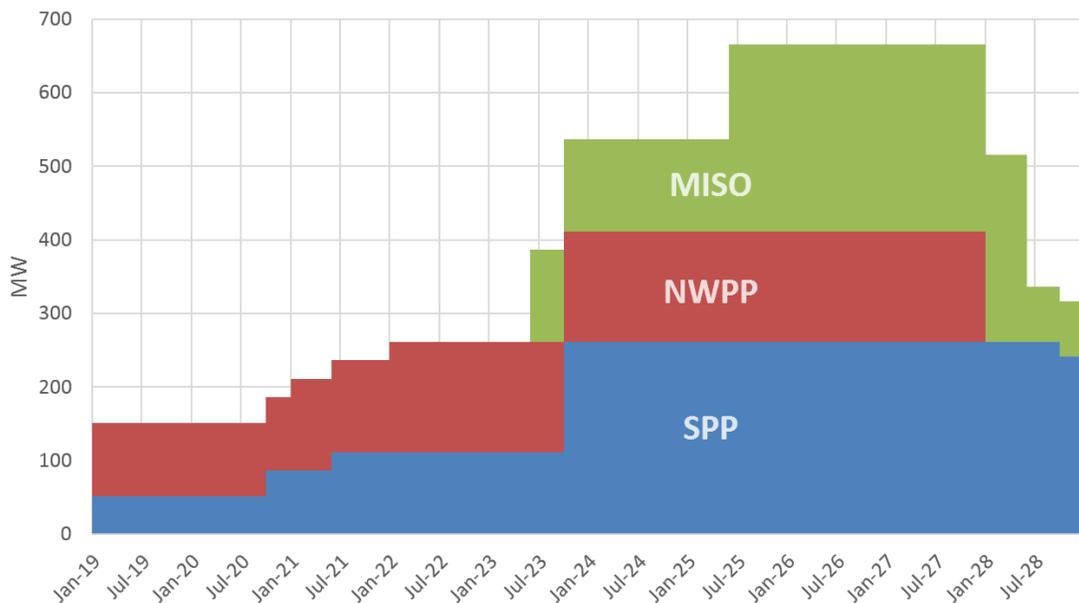


Figure 1-6 Basin Electric's Current Recommended Bilateral Purchases

Figure 1-7 through Figure 1-10 show Basin Electric’s revised summer season surplus capacity positions in the RMRG, NWPP, MISO LRZ 1, and SPP regions with the recommended bilateral purchases. No changes are being proposed in the MISO LRZ 3 region at this time.

With the proposed bilateral purchases in the RMRG region, 50 MW of Basin Electric’s entitlement share of the Laramie River Station in the western interconnection/RMRG region will shift over to the unit in the eastern interconnection/SPP region. This will reduce the amount of surplus capacity that Basin Electric has in RMRG.

RMRG System Summer Surplus Capacity

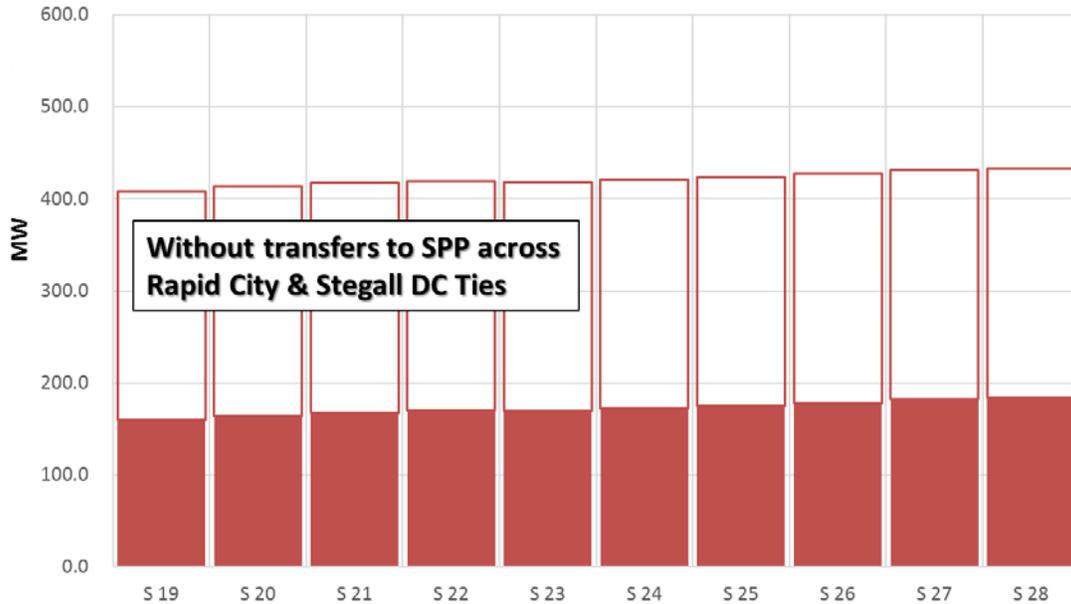


Figure 1-7 RMRG System Surplus Capacity with Current Recommended Bilateral Purchases

With the proposed bilateral purchases in the NWPP region, Basin Electric would not have to rely on supplying power from resources in SPP across the Miles City DC tie until 2026, at which time coincident peak demand obligations can still be met utilizing the Miles City DC tie until 2028.

NWPP System Summer Surplus Capacity

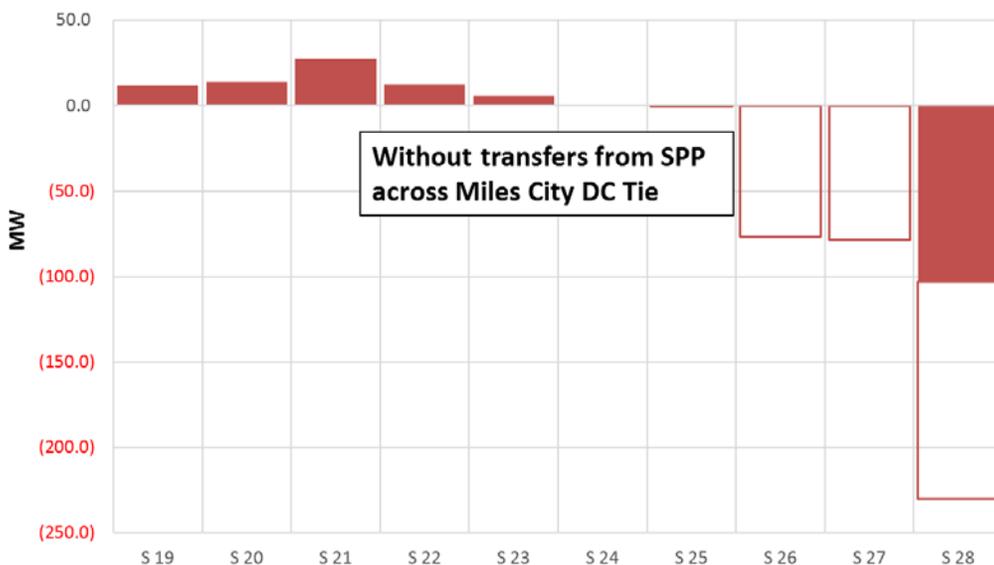


Figure 1-8 NWPP System Surplus Capacity with Current Recommended Bilateral Purchases

With the proposed bilateral purchases in the MISO LRZ 1 region, Basin Electric would not have to secure additional power supply for another two years, pushing the need out until 2025 instead of 2023.

MISO Zone 1 System Summer Surplus Capacity

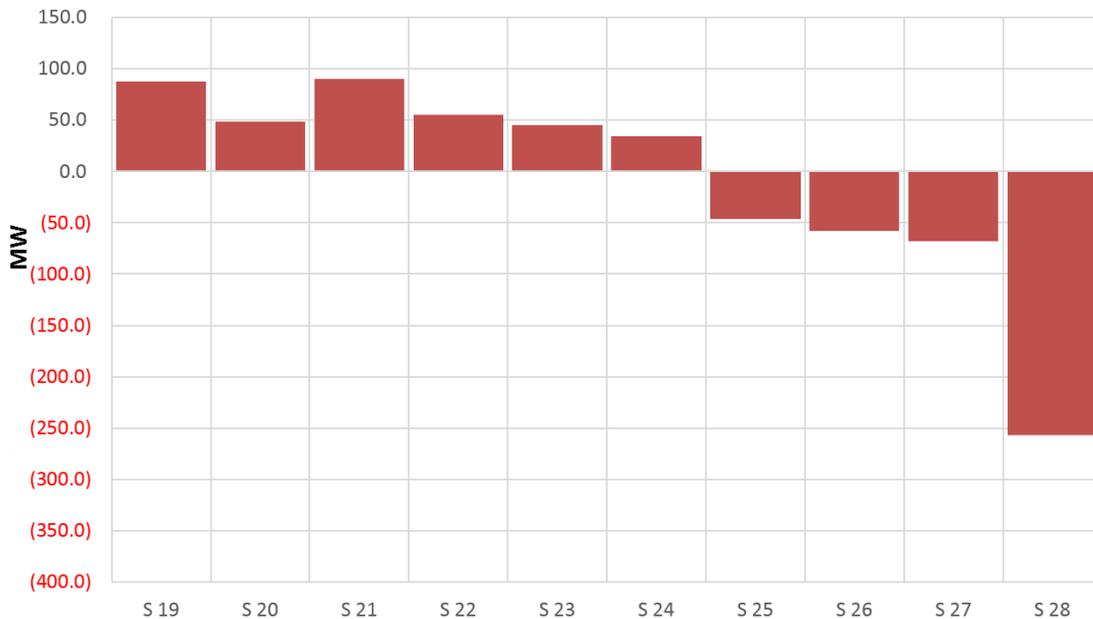


Figure 1-9 MISO LRZ 1 System Surplus Capacity with Current Recommended Bilateral Purchases

With the proposed bilateral purchases in the SPP region, Basin Electric could potentially push the need for additional power supply out another year to 2022, however there is still a pretty near-term need for more power supply resources than what is currently being proposed. Additional power supply options are still being analyzed.

SPP System Summer Surplus Capacity

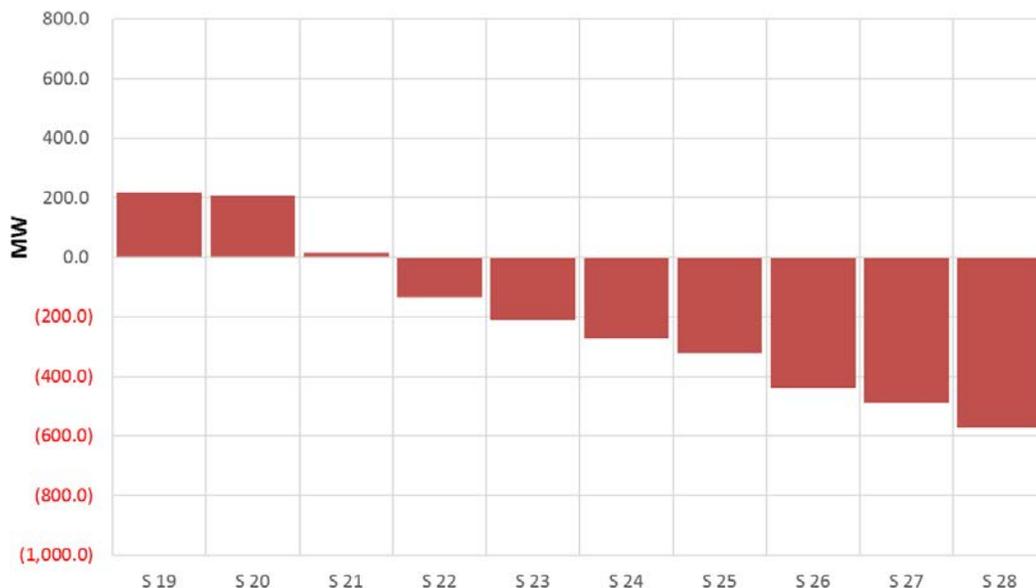


Figure 1-10 SPP System Surplus Capacity with Current Recommended Resource Expansion Plan

Basin Electric plans to try securing bi-lateral contracts in an attempt to create a power supply cliff event in the 2026-2028 time period to economically align the new resource timing with the market and our member's load growth. At this time, Basin Electric is working on solutions that support this strategy, yet continue to monitor market conditions, load growth, and the regional Reserve Margins that will directly impact the viability and economics of this strategy.

Five Year Action Plan

On the basis of these conclusions, and in order to ensure Basin Electric has adequate power supply available to meet our member's needs the following 5-year action plan will be implemented:

1. Monitor load growth - Uncertainty in various sectors such as coal and oil could cause additional impacts to Basin Electric's current forecasted projections.
2. Secure proposed bilateral purchases. Continue to monitor additional available low cost power supply options while Reserve Margins in the power supply planning regions exceed the minimum requirements and products are available.
3. Continue to work on developing and expanding upon energy conservation and efficiency within the Basin Electric service territory.
4. Increase Basin Electric's near term reliance on the energy markets while natural gas prices are low, the market is long energy, and as wind continues to develop over the next couple of years, while still being able to protect us from the exposure of the market by having an appropriate backstop of natural gas fueled generation.
5. Continue to evaluate additional alternatives to move surplus power from our system in the western interconnection to our system in the Southwest Power Pool to more appropriately align our portfolios in the various planning areas.
6. Continue to evaluate additional low cost renewable options to provide additional energy to meet member power requirements.
7. Continue to evaluate extending Basin Electric's Firm Electric Service Contract with Western for Firm Peaking Power Service beyond 2020.
8. Continue to work with the membership to support member electric marketing programs with a number of special rates.

2) Introduction

Study Scope

1. The 2018 Integrated Resource Plan (2018 IRP) provides an in depth look at Basin Electric's current operating system, future load growth and the framework for future expansion.
2. The 2018 IRP defines a five-year action plan to most effectively meet growing member needs and to provide low cost reliable power to its member owners.

Report Format/Components

To fulfill the study's scope, the report includes these main sections:

- 1) Executive Summary
- 2) Introduction
- 3) Basin Electric Overview
- 4) The Planning Environment
- 5) Transmission Planning
- 6) Load and Resource Balance
- 7) Resource Alternatives
- 8) Regional Power Supply Analysis
- 9) Analytical Approach
- 10) Risks and Uncertainties
- 11) Conclusion
- 12) Appendix A - Acronyms and Abbreviations
- 13) Appendix B - Model Description
- 14) Appendix C - Works Cited

Public Input Process

Basin Electric provides wholesale, supplemental electric service for 141 member cooperatives. Together these member electric power cooperatives direct Basin Electric to plan, design, construct, and operate the power generating and transmission facilities required to meet their power needs.

The load forecasts for each electric cooperative is developed every year in coordination with the local distribution cooperative and its respective Class A G&T. Each individual local distribution member's staff and management review and approves their forecast. After local distribution approval, the Class A G&Ts forecasts are rolled up and have their Board approve the G&T forecast. This load forecast is then brought to the Basin Electric Board for approval, at which point Basin Electric uses this load forecast in Basin Electric's power supply planning, transmission planning, financial forecasting, and rate setting processes.

This structure allows Basin Electric to receive input from the local distribution cooperative, the Class A G&Ts and Basin Electric's Board of Directors, all of which are members and subject to the electrical rates being set by Basin Electric's activities. In addition Basin Electric also has several Member Manager Advisory Committee (Member MAC) meetings each year to facilitate communication with the cooperative managers and Basin Electric. These meetings are geared to discuss activities that affect Basin Electric and the member cooperatives that Basin Electric serves. Basin Electric also has a Rate Subcommittee, which is a subset of the MAC, that digs into the finer details of Basin Electric's rates and vets through rate discussions prior to a recommendation from the MAC to support the proposed direction that is eventually proposed at the Basin Electric Board.

These processes and meeting are all designed to allow the membership to have representation and have a voice in the planning, financial and rate setting decisions being made at Basin Electric.

At this time of this IRP Basin Electric is not proposing any new resource buildouts and will be monitoring our future member power requirements for the next 5 year window, as will be described throughout this IRP. Any shortfalls in this time period will be handled with short term bi-lateral contracts and Basin Electric will continue to review the current state of wind and solar proposals that are in the market. If in the future it is decided that Basin Electric has a need to build a new resource, justification activities will follow required permitting and regulatory processes.

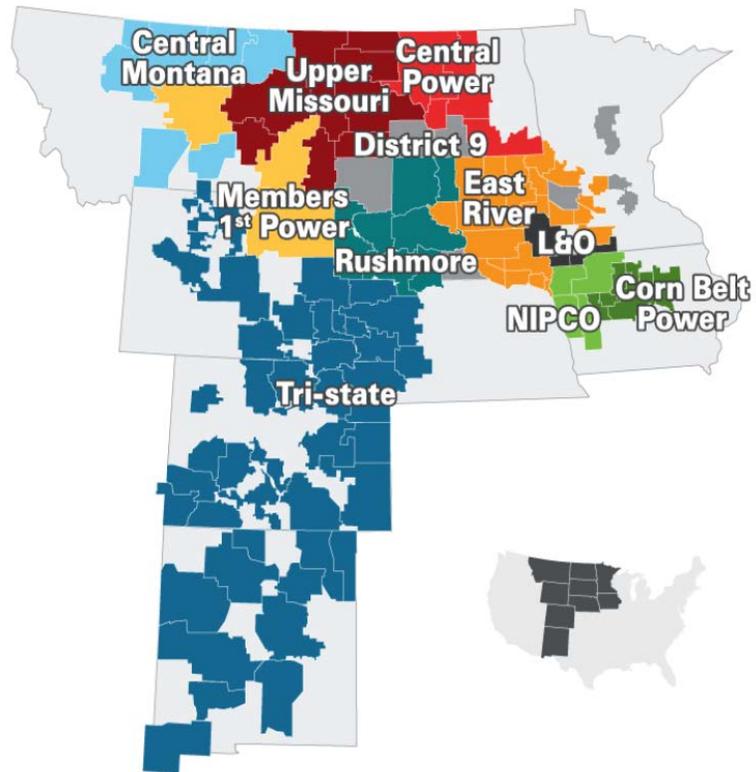


Figure 2-1 Basin Electric Membership Service Area

3) Basin Electric Overview

History

Basin Electric is a regional wholesale electric generation and transmission cooperative owned and controlled by the member cooperatives it serves. These cooperatives began operation in the 1940s and early 1950s as a result of Franklin D. Roosevelt's 1935 executive order establishing the Rural Electrification Administration (REA). At that time only 3.5 percent of the rural people of the Great Plains received central station electricity. The establishment of the REA made it possible for cooperatives to receive assistance in electrifying rural America where there were only one or two farms per mile of line. Prior to REA, electricity was not generally available in the rural areas, as investor-owned utilities had limited incentive to serve the low-density areas.

Initially, the Basin Electric member cooperatives obtained nearly all of their wholesale power requirements from the dams on the Missouri River, which were constructed by the Army Corps of Engineers in accordance with Congressional authorization provided in the Flood Control Act of 1944. The primary purpose of the dams was for flood control, with other benefits consisting of hydroelectric generation, irrigation, municipal water supply, recreation and navigation. The Bureau of Reclamation was charged with marketing the electricity generated at the dams. Their marketing was done in accordance with the 1944 Flood Control Act, which stated; "Preference in the sale of power and energy shall be given to public bodies and cooperatives." The preference customers, who consisted primarily of rural electric cooperatives, municipal electric systems, and public power districts, were assigned allocations of hydroelectric power by the Bureau of Reclamation to meet their power requirements. Since 1977, marketing of power has been performed by the Western Area Power Administration (Western), an agency of the U.S. Department of Energy (DOE).

With the assistance of the REA and the availability of the hydropower from the Missouri River dams, the electrification of the rural areas rapidly proceeded during the 1940s and 1950s. The increase in power usage by rural consumers quickly surpassed earlier projections as refrigerators, ovens, water pumps, grain dryers, feed grinders, lathes, welders, drills, heaters, radios, and lights in every room were obtained by the rural cooperative consumers.

In 1958, the Interior Department announced that the Bureau of Reclamation could not guarantee there would be sufficient generating capacity from the Missouri River dams to meet the increasing cooperative power requirements and, that additional sources of power would be needed.



The Garrison Dam power plant on the Missouri River in North Dakota

As a result, on May 5, 1961, sixty-seven (67) electric cooperatives joined together to form Basin Electric Power Cooperative, directing it to plan, design, construct, and operate the power generating and transmission facilities required to meet their increasing power needs. Basin Electric was organized on the basis of an open membership, so that all cooperatives that wished to join could share in the benefits.

About Us

Basin Electric is a generation and transmission (G&T) cooperative organized under the laws of the State of North Dakota. Basin Electric is composed of member cooperatives (in four classifications, described below) which, with the exception of the Class B Member, are G&T cooperatives or distribution cooperatives.

A G&T cooperative is a cooperative engaged primarily in providing wholesale electric service to its members, which generally consists of distribution cooperatives. Service by a G&T cooperative is provided from its own generating facilities or through power purchase agreements with other wholesale power suppliers either through bilateral contracts directly with the suppliers or through an energy market where available. A distribution cooperative is a local membership cooperative whose members are the individual retail consumers of an electric distribution system. Basin Electric is the largest G&T cooperative in the geographical area served. As of April 2018, Basin Electric provides wholesale, supplemental electric service for 141 member cooperatives in the states of Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming. Approximately 3 million consumers are served by Basin Electric's member cooperative systems.

Basin Electric Membership Classification

Class A Members are G&T cooperatives and distribution cooperatives that have entered into long-term wholesale power contracts with Basin Electric. Ten wholesale G&T cooperatives and eight distribution cooperatives are Class A Members of Basin Electric. Class A membership in Basin Electric gives such a member the right to vote at annual membership meetings and a seat on the Board of Directors (one seat for each of the 10 G&Ts and one seat for all eight distribution cooperatives).

Class B Members is available to any municipality or association of municipalities operating within an area served by a Class A Member and that is a member of and contracts for its electric power and/or energy from that Class A Member. Class B Members within any Basin Electric voting district are entitled to one vote collectively at annual membership meetings of Basin Electric. Basin Electric has one Class B member. The Class B member does not purchase power directly from Basin Electric.

Class C Members consists of 141 distribution cooperatives and public power districts that are members of the Class A G&T cooperatives defined above. Class C membership in Basin Electric gives that member the right to vote at annual membership meetings of Basin Electric. Class C Members do not purchase power directly from Basin Electric.

Class D Membership is available to an electric cooperative that purchases power from Basin Electric on other than the full Class A Member base rate. Class D Members may vote at the annual meeting, but have limited rights to vote in the election of directors. Basin Electric has one Class D Members.

Basin Electric has entered into wholesale power contracts with each of its Class A Members. Pursuant to the contracts with our eight Class A distribution cooperative members, one Class D member and ten Class A G&T cooperative members (which, in the aggregate, represented approximately 77.4 percent of Basin Electric's 2017 MWh sales to Class A Members), Basin Electric sells and delivers to each member its capacity and energy requirements over and above specifically enumerated amounts of power and energy available to such member from other specified sources, primarily Western.

Tri-State Generation & Transmission Association, Inc. (Tri-State) has entered into a wholesale power contract that requires Tri-State to buy and receive from Basin Electric: (i) with respect to Tri-State's Western Interconnection members, with contractual amounts between minimums of 103 MW and maximums of 268 MW and (ii) all of Tri-State's supplemental power and energy requirements for Tri-State's Eastern Interconnection members.

Each Class A Member is required to pay Basin Electric for capacity and energy furnished under its wholesale power contract in accordance with rates established by Basin Electric.

In 2015, Basin Electric worked with its membership to extend its Wholesale Power Contracts from 2050 to 2075. All but three of its members extended their contract to 2075. After such date, all wholesale power contracts remain in effect until terminated by either party giving appropriate notice per the requirements of the Wholesale Power Contract of its intent to terminate.

Service Territory and Membership

Figure 3-1 illustrates a map of Basin Electric's service territory.

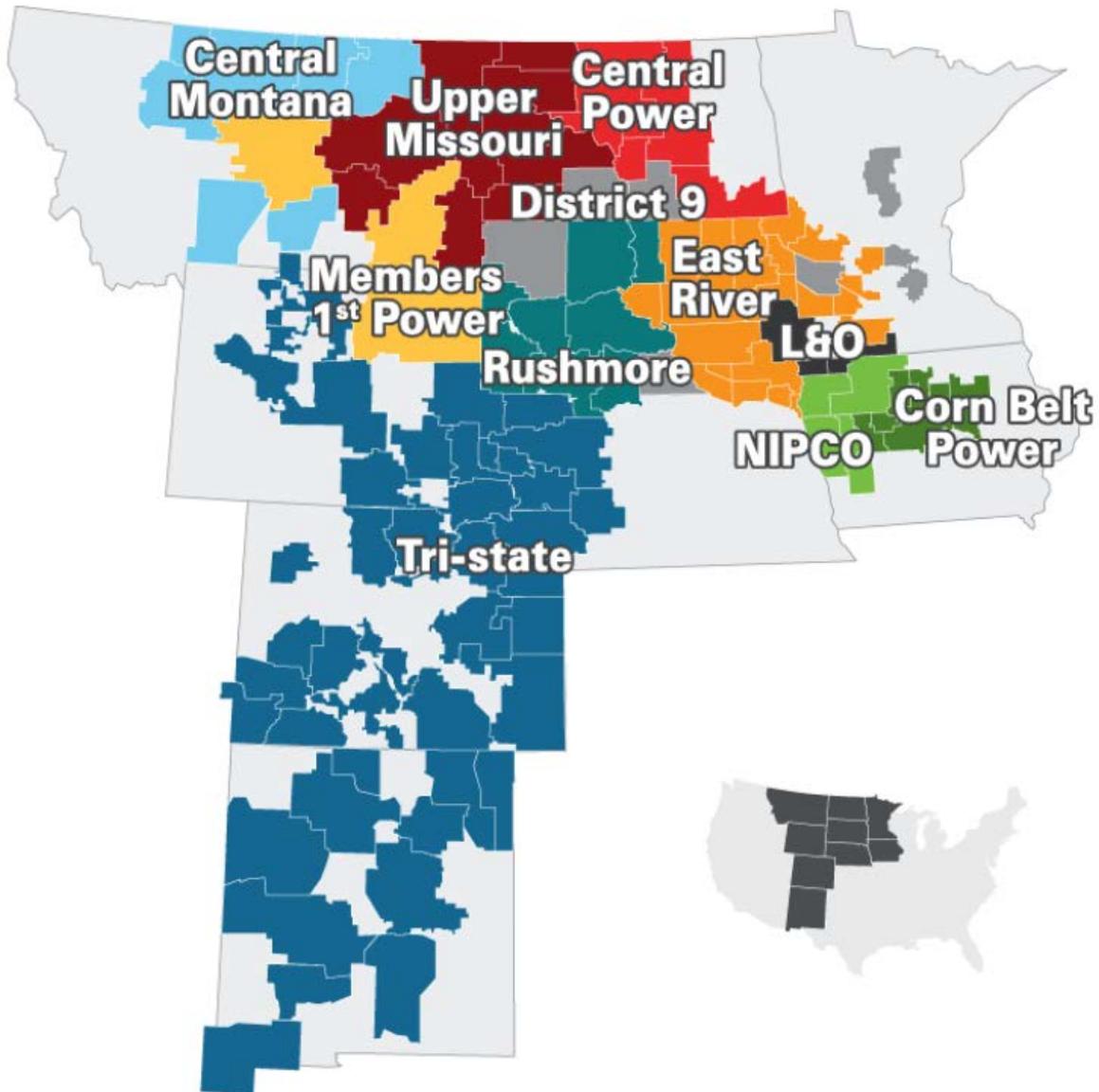


Figure 3-1 Basin Electric Membership Service Area

Class A Members

District 1 – East River Electric Power Cooperative (East River)

District 2 – L&O Power Cooperative (L&O)

District 3 – Central Power Electric Cooperative (Central Power)

District 4 – Northwest Iowa Power Cooperative (NIPCO)

District 5 – Tri-State G&T Association (Tri-State)

District 6 – Central Montana Electric Power Cooperative (Central Montana)

District 7 – Rushmore Electric Power Cooperative (Rushmore)

District 8 – Upper Missouri G&T Electric Cooperative (Upper Missouri)

District 9

Crow Wing Cooperative Power & Light Company (Crow Wing)

Grand Electric Cooperative (Grand)

KEM Electric Cooperative (KEM)

Minnesota Valley Cooperative Light & Power Association (Minnesota Valley CL&PA)

Minnesota Valley Electric Cooperative (Minnesota Valley EC)

Mor-Gran-Sou Electric Cooperative (Mor-Gran-Sou)

Rosebud Electric Cooperative (Rosebud)

Wright-Hennepin Cooperative Electric Association (Wright-Hennepin)

Class D Members

Flathead Electric Cooperative (Flathead)

District 10 – Members 1st Power Cooperative (Members 1st)

District 11 – Corn Belt Power Cooperative (Corn Belt)

Mission Statement

To provide wholesale energy and services to our member-owners.

Vision Statement

To be a leader in the energy industry through innovation and responsibility while delivering value to our member-owners.

Cooperative Principles

- Open and Voluntary Membership
- Democratic Membership Control
- Members' Economic Participation
- Autonomy and Independence
- Education, Training and Information
- Cooperation Among Cooperatives
- Concern for Community
- <https://www.electric.coop/seven-cooperative-principles%E2%80%8B/>

4) The Planning Environment

Introduction/Overview

Clean air and clean water are important to our environment and future generations. Our region continues to rank as one of the areas with the cleanest air in the nation, and almost all of our generation resources were built with best available pollution control technologies at the time of their construction. Our generation resources have long histories of compliance with environmental standards. As this history demonstrates, our commitment to the environment and environmental compliance remains strong and is a core value of our cooperative.

The last major amendment to the Clean Air Act, however, occurred in 1990. It has been long anticipated that Congress would pass legislation to address both the emission of carbon dioxide (CO₂) into the atmosphere and develop a concurrent energy policy, but because of legislative gridlock in Congress no major legislative changes have occurred. By default, the laws governing environmental and energy policy are developing through various rulemakings under the Executive Branch (primarily through the EPA), and in the Courts. The EPA, the Courts, industry, and environmental-NGO litigants are all grappling with underlying issues of how far old laws can be stretched to fit new circumstances.

It takes years for laws to develop and issues to become settled this way, which makes integrated resource planning an exercise of predicting short-term and long-term trends, and choosing options that are most likely to be permitted and built in a timely way to meet changing generation and transmission resource needs. This ad hoc “policy through regulation and litigation” will continue until Congress and the Executive Branch work together to craft a more workable solution. Despite this uncertain regulatory process, Basin Electric presses forward with planning the appropriate power supply portfolio to meet member cooperative needs.

Recent environmental projects at our main baseload generation facilities are discussed below follow by details of recent EPA rulemakings affecting integrated resource planning. The recent projects at our baseload generation facilities were initiated in response to EPA rulemakings. Basin Electric and subsidiaries have been proactive in meeting these new federal emissions standards ahead of schedule. Through year-end 2017, Basin Electric had invested \$1.67 billion in environmental control technology. Approximately \$177.96 million was invested in the operation and maintenance of those controls in 2017.

Recent Projects

The following projects have been undertaken at our majority-owned coal-based facilities to ensure compliance with federal standards. It is important to note that all of Basin Electric facilities are in full compliance with all federal and state environmental standards and permits.

- **Leland Olds Station:** The first round of EPA’s Regional Haze Rule requires greater emission control through the installation of Best Available Retrofit Technology, or BART at LOS. To achieve this, Basin Electric has installed wet limestone scrubbers in both units to control sulfur dioxide (SO₂) emissions. Unit 2’s scrubber was commissioned in 2012; Unit 1’s was commissioned in 2013. For NO_x control, BART required the installation of Selective Non-Catalytic Reduction (SNCR) technology on both units that were put into service in April of 2017. The BART compliance requirements were effective April 2017. Over-fire air combustion control has also been incorporated into both units at the Leland Olds Station. This technology introduces air high in the boiler, which reduces combustion temperatures. Since formation of nitrogen oxides (NO_x) is in large part a function of temperature and oxygen availability, over-fire air technology reduces these emissions. A refined coal process has also been installed on both units to help with mercury and NO_x reduction. A post-combustion sorbent injection system to provide additional

mercury control was put in place prior to April 2015. EPA finalized the Effluent Limitations Guidelines (ELG) rule on September 30, 2015. The ELG rule sets limits for seven types of wastewater generated from power plants including a zero-discharge limit on bottoms ash transport water (BATW). As a result of this rule, a submerged flight conveyor system that will recycle BATW is currently being installed at LOS, with an expected completion date in late 2018.

- Laramie River Station: Over-fire air combustion control technology was incorporated into all three units at the Laramie River Station in 2009, 2010, and 2011 to aid in the reduction of NO_x emissions. Low-NO_x burners were incorporated into all three units at the Laramie River Station between 2012, 2013, and 2014. LRS is also an affected BART facility. BART required additional NO_x controls of Selective Catalytic Reduction (SCR) system on Unit 1, scheduled to be completed by July 1, 2019 and SNCR on Units 2 and 3, scheduled to be completed by December 31, 2018.

A refined coal process has also been installed in all three units at LRS to help with mercury and NO_x reduction. A post-combustion mercury emission control system which injects activated carbon or another reagent was also installed on all units in 2015.

- Antelope Valley Station: The startup fuel has been switched from fuel oil to natural gas for both units. Under Further Reasonable Progress in the State of North Dakota's Regional Haze State Implementation Plan, AVS was required to install advanced overfire air technology and low-NO_x burners for enhanced control of NO_x. Unit 1 was retrofitted in the spring of 2014 and Unit 2 in the spring of 2016. For SO₂ removal, the capacity of the lime slaking system for the Antelope Valley Station's dry scrubbers was enhanced. The dry scrubber utilizes a lime based slurry to remove SO₂ emissions from flue gas as it passes through the dry scrubbers. The additional slaking capacity allows for more lime to be available should high sulfur lignite coal be burned. A refined coal process has also been installed in both units to help with mercury and NO_x reduction. A post-combustion mercury emission control system has been installed at both units.
- Dry Fork Station: Air-quality control system technology employed at Basin Electric's newest coal-based power plant includes low-NO_x burners, over-fire air and SCR to control NO_x emissions; reflux circulated fluid bed scrubber to control SO₂ emissions; and post-combustion activated carbon injection to control mercury emissions.

Current Federal Regulations

In recent years EPA has initiated major rulemakings that have required additional pollution controls on existing generation from fossil fuels, and created more stringent emission control requirements on new fossil-fuel generation. Significant cases and significant rulemakings affecting Basin Electric generation resources include:

- Supreme Court determines carbon dioxide (CO₂) is an "air pollutant" causing "air pollution" as defined by the Clean Air Act. *Massachusetts v. EPA* (2007).
- EPA Administrator makes endangerment finding under CAA § 202(a) that CO₂ emissions from automobiles "cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare." (December 15, 2009)
- Criteria pollutant national ambient air quality standards (NAAQS) becoming more stringent:
- Hazardous Air Pollutants (CAA § 112) Mercury and Air Toxics Standards (MATS) Rule. (February 16, 2012)
- Coal Ash Rule - Disposal of Coal Combustion Residuals (CCR) (April 17, 2015)
- Effluent Limitations Guidelines (ELG) (September 30, 2015)
- CO₂ and other Greenhouse Gases (GHGs)

- EPA’s “PSD and Title V Permitting Guidance for Greenhouse Gases” (March 2011)
- EPA’s New Source Performance Standards (NSPS) for CO₂ for New EGU Sources (CAA § 111(b): Initial Proposal Apr 13, 2012; revised proposal Jan 8, 2014)
- EPA’s Existing Source Performance Standards (ESPS) for CO₂ for Existing EGU Sources (CAA § 111(d): Initial proposed rule, June 2, 2014; final rule scheduled June 1, 2015; State Plans due June 30, 2016, with possibility of extension for 1 year for individual states, and for two years for states doing multi-state agreements). This rule has been stayed by the United States Supreme Court. EPA is in the process of repealing and replacing this rule.

The rulemaking with the highest potential to impact Basin Electric’s resource planning is the last one -- EPA’s ESPS for CO₂ for Existing EGU Sources. This and other related rulemakings are discussed in more detail below.

Air Toxics Rules for Reciprocating Internal Combustion Engines (RICE)

The EPA signed the final diesel generator air toxics rule, also known as the RICE (reciprocating internal combustion engines) rule, on January 14, 2013. This rule finalizes amendments to the national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines. The final rule tightens emission controls but allows for greater demand response than the proposed version.

Emergency engines may now be used to prevent electrical outages and for testing and maintenance for a total of up to 100 hours per year. As of 2015, emergency engines will be required to burn ultra-low sulfur diesel (ULSD) if they operate or commit to operate for more than 15 hours each year as part of demand response. Also starting in 2015, operators of engines greater than 100 hp operating or committing to operate for more than 15 hours annually for demand response were required to collect data for and submit an annual report. Emergency engines that commit to running less than 15 hours annually for emergency demand response are not required to meet federal control requirements or emission limits.

The 100 hours per year limit for emergency engines includes the following activities/purposes:

- Monitoring and testing;
- Emergency demand response for Energy Emergency Alert Level 2 situations;
- Responding to situations where there is at least a 5 percent or more change in voltage; and
- Operating for up to 50 hours to head off potential voltage collapse, or line overloads, that could result in local or regional power disruption.

In the event of an emergency, there is no limit for operating hours or emission limits. EPA also allowed engines to be used for “peak shaving” for 50 hours per year at area sources until May 2014. After May 3, 2014, large diesel generators that have previously been utilized for peak shaving are no longer be available for that purpose.

Electric Generating Unit (EGU) Boiler Maximum Achievable Control Technology (MACT) for Mercury and Air Toxics Standards (MATS)

The EPA promulgated Maximum Achievable Control Technology (MACT) standards for mercury for existing units on February 16, 2012. According to the EPA, the standards could be met by 56 percent of coal- and oil-fueled electric generating units using pollution control equipment already installed; the other 44 percent

would be required to install technology that will reduce uncontrolled mercury and acid gas emissions by about 90 percent, at an annual cost of \$9 .6 billion.

Following promulgation of these standards, existing power plants had three years, with a possible one- year extension, to meet the standards. Standards for new facilities are more stringent, and many, including the industry that manufactures pollution control and monitoring equipment, doubt whether compliance with the mercury portion of these standards could be measured. In response to industry petitions, EPA agreed to reconsider the mercury limit for new facilities on July 20, 2012. On April 24, 2013, EPA published updated emission limits for new power plants.

Regional Haze

The EPA's Regional Haze Rule requires state and federal agencies to work in cooperation to improve visibility in 156 national parks and wilderness areas considered Class I areas. There are multiple rounds of regional haze planning and implementation with the goal of reaching background visibility levels in Class I areas by 2064. States are required to develop State Implementation Plans (SIPs) to reduce pollution that negatively impacts visibility. Once a SIP has been developed, EPA reviews the plan and either approves parts or the entire plan. The EPA will then issue a Federal Implementation Plan (FIP) if necessary.

For the first round, in North Dakota, the EPA partially approved the SIP and issued a FIP for the remaining portions. The state of North Dakota filed an appeal on the FIP. The EPA proposed to approve the North Dakota SIP in April 2018.

In Wyoming, the EPA has approved most of the SIP. However, prior to issuing a final FIP/SIP, the EPA announced additional information needed to be considered. EPA has issued its final SIP/FIP for Wyoming. Basin Electric has worked with EPA and the Wyoming Department of Environmental Quality on a BART Settlement which is expected to be finalized in the fall of 2018.

North Dakota and Wyoming will need to develop their second regional haze plan for the 2018-2028 timeline that achieves the reductions required to meet the Uniform Rate of Progress to natural conditions in 2064. The second regional Haze planning period SIP is required by July 31 of 2021.



Coal ash was an additive in the concrete used to build the Memorial Bridge across the Missouri River in Bismarck, ND in 2008.

Coal Combustion Residue (CCR)

The Disposal of Coal Combustion Residuals (ash) from Electric Utilities Final Rule was released on April 17, 2015. This rule regulates CCR as a non-hazardous waste. The rule contains location, design, monitoring, closure and post-closure care, and recordkeeping requirements. The rule is self-implementing and will be enforced through citizen suits.

Compliance with the CCR rule is ongoing, with rule requirements completed according to the phase-in schedule dictated by the rule. Additional monitoring wells have been installed at all affected facilities. Various plans, demonstrations, and certifications required by the rule have also been completed. Facility location restriction certifications are due in late 2018. The Water Infrastructure Improvements for the Nation (WIIN) Act allows state agencies to apply for primacy over this program. If approved, the applicable state agency would oversee implementation of the rule. Both North Dakota and Wyoming are working through this process.

EPA's revision of the CCR Rule was published on Monday, July 30, 2018. The revision gives states with the CCR permit program approval the ability to use alternate performance standards, revises the groundwater protection standards for certain parameters, and most significantly, provides facilities which are triggered into closure because of groundwater contamination additional time (until October 31, 2020) to cease receiving water and initiate closure.

Greenhouse Gas Regulations - Existing and New Source Performance Standards (GHG - ESPS & NSPS)

Basin Electric historically has relied on mine-mouth or near-mine-mouth coal-fueled baseload generation to provide affordable and reliable electricity to its member-owner customers. Since the GHG initiatives relating to EGUs began – first for new sources, now for existing sources – Basin Electric has taken steps to diversify its generation resource mix to protect against these anticipated GHG regulations, and to construct in a timely way new generation resources that do not face the permitting and litigation delays that a new coal-based resource now encounters. These trends will likely continue until the regulations become less dependent on the policy choices of the Executive Branch, and more dependent on legislation that clearly defines policy and jurisdiction over regulation of greenhouse gases. Until then, new resource choices will have to be lower carbon intensity natural gas generation or renewables that can be permitted in a timely way, and existing generation will be in a continuing battle to remain on-line under regulations that are designed to force higher-carbon-intensity existing generation to run less in favor of the newer low-carbon-intensity generation.

Regulation of CO₂ and other greenhouse gases from EGUs has occurred in a series of steps that commenced in 2009 and continue through the current time (summer 2018).

The first major step was the determination by EPA Administrator Jackson released on September 30, 2009, that reversed former EPA Administrator Stephen L. Johnson's determination not to regulate CO₂ for permitting purposes under the prevention of significant deterioration (PSD) provisions of the Clean Air Act. The September 30, 2009, proposed rule "tailored" the CO₂ PSD permitting requirements that emitted more than 25,000 tons (rather than the 250 tons defined by the Clean Air Act to define a "major source"). The final rule set the limits at 100,000 tons of CO₂ as the threshold for requiring a PSD permit and "best available control technology" (BACT) for a new EGU, and 75,000 tons for any source undergoing a major modification. Five years later, in June 2014, the U.S. Supreme Court threw out these "tailored" amounts for CO₂ because

they were not consistent with the statute, but determined that BACT would still apply to CO₂ emissions from a new source if BACT review is triggered by any other regulated air pollutant that exceeds the major source threshold (either 250 or 100 tons, depending on the pollutant). *Utility Air Regulatory Group v. E.P.A.*, 134 S. Ct. 2427 (2014). As a result, PSD BACT requirements will continue to apply to CO₂ emissions from any generation source that triggers major source review for another pollutant such as SO₂ or NO_x.

In March of 2011, EPA issued its final guidance document to the States on how they were to consider CO₂ and GHG BACT. Since that time, any source that emitted CO₂ over the “tailored” amounts (100,000 tons per year) has had to do a BACT analysis for GHGs. Although the *Utility Air Regulatory Group (UARG)* decision now limits GHG/CO₂ BACT analyses to EGUs that trigger major source review for another pollutant other than CO₂, most large EGUs will exceed those limits for one of the “criteria” pollutants, and most large new EGUs will still have to do PSD BACT analyses before they can receive a construction permit.

In April 2012, EPA released its proposed New Source Performance Standards (NSPS) for CO₂ for New EGU Sources (CAA § 111(b)). This proposal required that any new EGU constructed after that date not emit more than 1,000 pounds of CO₂ per megawatt hour of electricity generation produced. Since the NSPS becomes the “floor” for BACT (i.e., BACT requires that no new source can emit more CO₂ than NSPS for that category of sources than the NSPS standard allows), no new coal generation has been permitted, because new coal EGUs cannot meet that standard without carbon capture and sequestration (CCS), which is not feasible because CCS is not proven at a commercial-scale for EGUs, and is too expensive to build compared to other available forms of generation.

On Jan 8, 2014, EPA slightly revised the NSPS for EGUs, keeping the NSPS for natural gas combined cycle generation at 1,000 lbs/MWh, but slightly increasing the coal EGU NSPS to 1,100 lbs/MWh. This increase is not enough to make new coal EGU a cost-effective option.

On October 23, 2015, the most recent Executive Branch rulemaking affecting EGUs was released. This is the “existing source performance standards” (ESPS) for CO₂ emissions from existing EGUs. These regulations identify the “best system of emission reduction (BSER) which ...the (EPA) Administrator determines has been adequately demonstrated” for CO₂ from existing EGUs under the provisions of Clean Air Act. The state-by-state BSER goals are set by a weighing of four factors or “building blocks”:

- Efficiency improvements at each EGU of 6%;
- A displacement of coal-generation by natural gas combined cycle (NGCC) generation up to a capacity of 70% for NGCC;
- A displacement of coal by renewables up to the average renewable portfolio standards of the states in each of six defined regions; and

EPA has set the proposed GHG emission standards at a level achievable by natural-gas fired units or by coal-fired units using CCS technology. Although the components of CCS technology have been demonstrated, no existing power plant combines them all in an operating unit. The electric power industry has generally concluded that a CCS requirement would effectively prohibit the construction of new coal-fired plants, other than those already permitted. Previously, EPA had maintained otherwise, but has also said that, because of low natural gas prices and abundant existing generation capacity, it believes no new coal-fired units subject to the proposed standards will be constructed between now and 2020. In the meantime, new generation will be restricted to forms of generation that can cost-effectively meet the NSPS and BACT requirements, and be permitted in a timely way.

This Final Rule was immediately challenged in the courts. Oral arguments were heard by the D.C. Circuit Court of Appeals on September 27, 2016. The Final Rule was stayed by the Supreme Court of the United States for the duration of litigation on February 9, 2016. The Department of Justice filed a motion on March 28, 2017, asking the D.C. Circuit Court of Appeals to hold the case in abeyance. On April 28, 2017, the D.C. Circuit Court of Appeals abated the case for 60-days. The D.C. Circuit has continued to hold the case in abeyance, most recently issuing an order to extend the abeyance on June 26, 2018. On April 4, 2017, EPA announced that it was initiating administrative review of the rule. On June 8, 2017, EPA submitted to the Office of Management and Budget (OMB) for review a proposed rule titled, "Review of the Clean Power Plan." The proposed rule to repeal the existing CPP was published on October 16, 2017. EPA published an Advance Notice of Proposed Rulemaking (ANPRM) on December 28, 2017. The intent of the ANPRM was to solicit information on what a replacement rule should contain.

Criteria Pollutants under the National Ambient Air Quality Standards (NAAQS)

NAAQS are the cornerstone of the Clean Air Act, in effect defining what EPA considers to be clean air. They do not directly limit emissions, but they set in motion a process under which "nonattainment areas" are identified and states and EPA develop plans and regulations to reduce pollution in those areas. Nonattainment designations may also trigger statutory requirements, including that new major sources offset certain emissions by reducing emissions from existing sources.

Currently, there are NAAQS for six pollutants: ozone, particulate matter, sulfur dioxide, carbon monoxide, nitrogen dioxide, and lead. The Clean Air Act requires that these standards be reviewed every five years, and all of the standards have been under court-ordered deadlines for review.

Sulfur Dioxide (SO₂)

On April 17, 2014, the U.S. Environmental Protection Agency (EPA) proposed requirements for air agencies to characterize sulfur dioxide (SO₂) air quality more extensively across the country for purposes of implementing the 1-hour SO₂ National Air Ambient Quality Standards (NAAQS). The proposed rule includes options for emissions thresholds which would identify the sources around which air agencies would need to characterize SO₂ air quality. To increase public health protection in more highly populated areas, each option includes a lower annual emissions threshold for sources located in metropolitan areas greater than 1 million in population, and a higher threshold for sources outside these areas. Air agencies can avoid a nonattainment designation for an area by working with sources to establish permanent and enforceable emission limitations that show attainment with the SO₂ standards through modeling prior to the next round of designations in 2017. Compliance with other emission reduction programs, such as the Mercury and Air Toxics Standards for power plants and emission standards for boilers, may help these areas improve ambient SO₂ air quality earlier. Both North Dakota and Wyoming have submitted sufficient information to EPA for an "attainment" area determination. The Lignite Energy Council (LEC) submitted comments regarding the North Dakota determination. Basin Electric submitted comments regarding the Wyoming determination. On January 9, 2018, the EPA published a final rule establishing air quality designations for certain areas of the United States for the 2010 SO₂ NAAQS. All areas of Montana, North Dakota, South Dakota, and Wyoming were classified as either Attainment or Attainment/Unclassifiable. On May 29, 2018, EPA released a proposed rule that would retain the primary (health-based) NAAQS for SO₂ at 75 parts per billion (ppb). The Final Rule was effective on April 9, 2018.

Ozone

On March 1, 2018, EPA released a final rule entitled “Implementation of the 2015 National Ambient Air Quality Standards for Ozone: Nonattainment Area Classifications Approach”. The Final Rule established air quality thresholds and attainment dates for nonattainment areas for the 2015 national ambient air quality standards for ozone. All states in which Basin Electric operates generation facilities were designated as in attainment.

Requirements for Cooling Water Intake Structures at Existing Facilities 316(b)

On May 19, 2014, the EPA finalized standards to protect aquatic life drawn into cooling water systems at large power plants and factories. There are three main components to the final rule. The first component is that existing facilities which withdraw at least 25 percent of their water from an adjacent waterbody exclusively for cooling purposes and have a design intake flow of greater than 2 million gallons per day. The second part requires facilities that withdraw at least 125 million gallons per day to conduct studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms entrained by cooling water systems. The final part of the rule requires new units that add electrical generation capacity at an existing facility are required to add technology that achieves one of two alternatives under the national BTA standards for entrainment for new units at existing facilities. North Dakota utilities that withdraw water from the Missouri River have started discussions to identify areas for cooperation in developing base studies to support the compliance requirements. The 316(b) program requires impingement and entrainment data for LOS due to the Once-through-Cooling design. The two-year entrainment study that began at LOS in April 2015 was completed in September 2016. For LOS, the required reports and assessments were completed in 2018. The NDDoH will incorporate their determination of BTA for LOS into the North Dakota Pollution Discharge Elimination System (NDPDES) permit at its next renewal cycle which is 2021. LOS would then have adequate time to install the identified BTA. The implementation of the rule was within 44 months of the December 2016 permit renewal at LOS allowing Basin Electric to request an extension. A compliance extension was requested and granted for LOS. This rulemaking also required 316(b) submittals on a lesser extent for the water intakes at AVS and LRS. Both AVS and LRS have submerged water intakes and closed cooling systems that are considered BTA. For AVS the State of North Dakota incorporated aspects of the 316(b) program in the language in the NDPDES Permit issued in June 2018. The State of Wyoming permit renewal is still anticipated to be completed in the fall of 2018.

Future Federal Regulations

Federal Climate Change Legislation

There is a proposed rule to replace the Clean Power Plan rule that is currently being stayed, known as the Affordable Clean Energy (ACE) rule, was published August 31, 2018. The proposed ACE rule would require states to evaluate heat rate improvement (HRI) projects at each individual applicable source. The proposed ACE rule also includes revised provisions for the implementation of emission guidelines and new source review (NSR) revisions. At this time Basin Electric is not making any plans or decisions based on this proposed ACE rule, but will continue monitoring its progress as it goes through the 60 day comment period and likely the litigation process to follow.

State Policy Update

ND Flaring Rules

In 2014 and amended in 2018, the North Dakota state Industrial Commission adopted rules regulating the burning off, or “flaring”, of natural gas at well sites after nearly a third of the gas was flared raising concerns of wasted revenue and unnecessary polluting. The original goals that were established in 2014 required 85% of all the natural gas extracted to be captured (maximum of 15% could be flared) starting in January 2016 through September 2020 then increasing to 90% beginning October 1, 2020. The amended rules reduced the final goal from 90% to 88% but moved the compliance date up from October 1, 2020 to November 1, 2018. Failure to comply with the goals can result in civil penalties ranging from \$1,000 per month up to as much as \$12,500 per well for each day the well has been in violation.

Oil companies have stated they are committed to meeting the goals and will do what they have to do to meet them, even if that requires cutting back on production. Another possible alternative is to burn the natural gas onsite in natural gas fired electric generators. Both of these paths will have an impact on Basin Electric, the former resulting in reduced loads in our Member systems and the latter resulting in more energy being injected onto the grid, making our older more expensive coal-fired generators struggle more to compete in the market.

Federal Renewable Energy Tax Credits

Wind Production Tax Credits (PTCs) and solar Investment Tax Credits (ITCs) are tax incentives passed by Congress originally as part of the Energy Policy Act of 1992 for the PTCs and the Energy Policy Act of 2005 for the ITCs. Generally speaking, PTCs are an income tax credit based on the energy generated by qualifying renewable facilities (originally \$15/MWh but has since been increased for inflation to \$23/MWh) while ITCs allow investors to claim 30 percent of the capital investments against their tax liability.

Both PTCs and ITCs have been extended multiple times, the most recent of which was in December 2015 as part of the Consolidated Appropriations Act of 2016. This act gave them a 5 year extension and phase-down period and it modified the language so that eligibility was based on when the projects begin construction as opposed to when they begin to generate power. The new act defined the commencement of construction having to meet at least one of two tests, the Five Percent Safe Harbor Test or the Physical Work Test¹. The Five Percent Safe Harbor Test determines the project has officially began construction if at least 5% or more of the total costs of the project have been incurred. The Physical Work Test requires that physical work of a “significant nature” must begin in order for the project to be deemed as under construction. Once it is deemed that construction has commenced, they have until the end of the fourth calendar year to finish construction and begin operation to claim the credits.

- Wind PTC Phase Out:
 - 100% of the current credit value for projects that commence construction before the end of 2016
 - 80% of the current credit value for projects that commence construction before the end of 2017
 - 60% of the current credit value for projects that commence construction before the end of 2018
 - 40% of the current credit value for projects that commence construction before the end of 2019
 - 0% thereafter

¹ (Commence Construction Guidance, 2018)

- Commercial Solar ITC Phase Out (for residential projects, replace “start construction” with “are placed in service”):
 - Full 30% for projects that start construction before January 1, 2020
 - 26% for projects that start construction in 2020
 - 22% for projects that start construction in 2021
 - 0% thereafter

Renewable Portfolio Standards

Several states within Basin Electric’s service territory have adopted Renewable Energy Objectives (REO’s) that requires renewable generation to meet a certain percentage of retail sales in that state. Many states in the Basin Electric membership service territory adopted REO’s such as Colorado, Minnesota, Montana, North Dakota, South Dakota and New Mexico and several states have not which include Iowa, Nebraska and Wyoming. The following information provides details of the adopted REO’s.

Colorado

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency Requirements | Treatment of Hydro |
|----------|---|--|---|
| Colorado | <p>MANDATORY 1%-2008-2010 3%-2011-2014 6%-2015-2019 10%2020-and Thereafter</p> <p>2018 Update: Electric coops serving 100,000 or more meters: 20% by 2020 Electric coops serving fewer than 100,000 meters: 10% by 2020</p> | None | (IV) "RENEWABLE ENERGY RESOURCES" MEANS SOLAR, WIND, GEOTHERMAL, BIOMASS, NEW HYDROELECTRICITY WITH A NAMEPLATE RATING OF TEN MEGAWATTS OR LESS, AND HYDROELECTRICITY IN EXISTENCE ON JANUARY 1, 2005, WITH A NAMEPLATE RATING OF THIRTY MEGAWATTS OR LESS. |

Table 4-1 Colorado REO

2. Colorado Conservation & Energy Efficiency Requirements

- a. The State of Colorado has no requirements with respect to conservation or energy efficiency.

3. Renewable Energy Requirements

- a. Standard: 40-2-124 Renewable Energy Standard provides, "Each provider of retail electric service in the state of Colorado, other than municipally owned utilities that serve forty thousand customers or less, shall be considered a qualifying retail utility. Each qualifying retail utility, with the exception of cooperative electric associations that have voted to exempt themselves from commission jurisdiction pursuant to section 40-9 .5-104 and municipally owned utilities, shall be subject to the rules established under this article by the commission.

(IV) To the extent that the ability of a qualifying retail utility to acquire eligible energy resources is limited by a requirements contract with a wholesale electric supplier, the qualifying retail utility shall acquire the maximum amount allowed by the contract. For any shortfalls to the amounts established by the commission pursuant to subparagraph (I) of this paragraph (c), the qualifying retail utility shall acquire an equivalent amount of either renewable energy credits; documented and verified energy savings through energy efficiency and conservation programs; or a combination of both . Any contract entered into by a qualifying retail utility after December 1, 2004, shall not conflict with this article:

- b. Hydro/Waste Heat Energy: 40-2-124 (VI) Renewable Energy Standard provides, defines Recycled Energy as, "solar, wind, geothermal, biomass, and new hydroelectricity with a nameplate rating of ten megawatts or less, and hydroelectricity in existence of January 1, 2005 with a nameplate rating of thirty megawatts or less ." Additionally, Colorado law provides that Recycled Energy means, "a means energy produced by a generation unit with a nameplate capacity of not more than fifteen megawatts that converts the otherwise lost energy from the heat from exhaust stacks or pipes to

electricity and that does not combust additional fossil fuel . “Recycled Energy” does not include energy produced by any system that uses energy, lost or otherwise, from a process whose primary purpose is the generation of electricity, including, without limitation, any process involving engine-driven generation or pumped hydroelectricity generation .”

- c. Reporting Requirements & Time Periods: 40-2-124 (5 .5) Procedure for exemption and inclusion-election provides that, “Each cooperative electric association that is a qualifying retail utility shall submit an annual compliance report to the commission no later than June 1 of each year in which the cooperative electric association is subject to the renewable energy standard requirements established in this section. The annual compliance report shall describe the steps taken by the cooperative electric association to comply with the renewable energy standards and shall include the same information set forth in the rules of the commission for jurisdictional utilities. Cooperative electric associations shall not be subject to any part of the compliance report review process as provided in the rules for jurisdictional utilities. Cooperative electric associations shall not be required to obtain commission approval of annual compliance reports, and no additional regulatory authority of the commission other than that specifically contained in this subsection (5.5) is created or implied by this subsection (5.5) .”
- d. Cooperatives that provide service to 10,000 or more meters: 1% of retail sales by 2020 must come from Distributed Generation (as defined in law), of which, half must be "retail distributed generation" serving on-site load
Cooperatives that provide service to less than 10,000 meters: 0.75% of retail sales by 2020 must come from Distributed Generation (as defined in law), of which, half must be "retail distributed generation" serving on-site load
- e. Compliance Multipliers:
 - 1.25 for electricity generated from eligible energy resources beginning operation prior to 2015 (excludes retail DG)
 - 1.50 for electricity generated at a “community-based project”
 - 3.00 for electricity generated from solar located in the territory of a cooperative or municipal utility; the electricity must be generated by a facility that begins operation before July 1, 2015, for electric cooperatives and by December 31, 2016, for municipal utilities
 - 2.00 for electricity generated by projects up to 30 MW that are interconnected to electrical transmission or distribution lines owned by a cooperative or municipal utility that are installed prior to December 31, 2014.
- f. Shelf life-RECs expire at the end of the fifth calendar year following the calendar year in which it was generated.

Iowa

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|------|-------------------------------|--|--------------------|
| Iowa | None | Co-ops must file with IUB by 7/1 even numbered years. Iowa Statewide files for members. | N/A |

Table 4-2 Iowa REO

2. Conservation & Energy Efficiency Requirements

- a. Cooperatives in Iowa must file energy efficiency plans with the Iowa Utilities Board (IUB) by July 1 of even-numbered years. The IUB does not review or approve these plans, nor does it verify the information filed. The IUB simply compiles the results of the plans. The goals and implementation of plans by cooperatives are not the responsibility of the IUB. However, IUB rules [199 IAC Chapter 36] specify the data cooperatives should provide in their plans.
- b. The IUB typically sends each consumer-owned utility a reminder in the spring of the year plans are due, including a form which utilities may use to compile and report the data for their plans. Cooperatives in Iowa are allowed to file their plans jointly with other utilities. For the past 14 years and continuing in 2006, the Iowa Association of Electric Cooperatives (IAEC) has filed joint plans for many of their member utilities. There are no specific requirements for the amount of energy that needs to be conserved each year.

3. Renewable Energy Requirements

- a. At this time, Iowa does not have any renewable energy requirements.

Minnesota

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|-----------|--|--|---|
| Minnesota | <p>GOOD FAITH OBJECTIVE until 2012 then MANDATORY</p> <p>7%- 2010-2011 12%- 2012-2015 17%- 2016-2019 20%- 2020-2024 25%-2025</p> | <p>CIP- 1.5 percent of the utility's annual retail energy sales in MN (ER, MN Valley L&P and SVE file)</p> | <p>Eligible Renewable- hydro with a capacity of less than 100 megawatts is considered an "eligible energy technology".</p> <p>Calculation of total Retail Sales: Western allocations are included in definition of retail sales so ER & L&O cannot deduct those from the baseline amount.</p> |

Table 4-3 Minnesota REO

2. Conservation & Energy Efficiency Requirements

- a. The Next Generation Energy Act of 2007 revised the CIP statute (Minnesota Statute 216B .241) to set an annual energy savings goal for each electric and gas utility beginning in 2010. The energy savings goal is equivalent to 1.5 percent of the utility's annual retail energy sales in Minnesota, averaged over the most recent 3-year period and weather-normalized. In certain circumstances, the Department of Commerce may reduce a utility's energy savings goal at its request. However, 1 percent is the minimum energy savings goal percentage. Electric utilities are required to invest 1.5 percent of their annual revenues in CIP Beginning in 2002, rural electric cooperatives and municipal utilities were required to spend the same amount as regulated utilities (1.5 percent for electric, and 0.5 percent for natural gas) on energy conservation programs. Utilities must file their CIP plans with the Department of Commerce at least every three years on a schedule determined by the commission. In 2010, the statutory energy savings goals established by the Next Generation Energy Act of 2007 take effect. Utilities were required to develop plans to meet at least the 1.0 percent minimum saving goal specified, measured as a percent of average retail electricity.
- b. Energy savings resulting from electric utility infrastructure upgrade projects approved by the public utilities commission or certain waste heat recovery projects may be counted towards a utility's energy savings goal in addition to the 1 percent savings floor for energy conservation programs
- c. Minnesota members file their CIP reports with the Minnesota Office of Energy Security (OES).

3. Renewable Energy Requirements

- a. 216B.1691 RENEWABLE ENERGY OBJECTIVES: Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail consumers, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies . An "Electric utility" means a public utility providing electric service, a generation and transmission (G&T) cooperative electric

association, a municipal power agency, or a power district. On November 12, 2008, the MN PUC issued an order establishing the requirement of renewable energy in the years 2008 and 2009 at 1%.

- b. Eligible energy technology standard - (a) Except as provided in paragraph (b), each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated. See table below.
- c. Hydro: hydroelectricity with a capacity of less than 100 megawatts is considered an "eligible energy technology."

Montana

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|---------|--|--|--|
| Montana | <p>NO REQUIREMENT FOR COOPERATIVES WITH LESS THAN 5,000 MEMBERS</p> <p>2010-2014- 10% 2015-15%</p> <p>Co-op Exemption: 1) A cooperative is exempt from the graduated renewable energy standard (2) Each governing body of a cooperative utility that has 5,000 or more customers is responsible for implementing and enforcing a RES for that cooperative that recognizes the intent of the legislature to encourage new renewable energy production and rural economic development, while taking into consideration the effect of the standard on rates, reliability, and financial resources</p> <p>*Park & Sun River are only cooperatives over 5,000 customers</p> | None | <p>Eligible Renewable- "Eligible renewable resource" means a facility either located within MT or delivering electricity from another state into MT that commences commercial operation after January 1, 2005, and that produces electricity from one or more of the following sources: (d) water power, in the case of a hydroelectric project that: (i) does not require a new appropriation, diversion, or impoundment of water and that has a nameplate rating of 10 megawatts or less; or (j) is installed at an existing reservoir or on an existing irrigation system that does not have hydroelectric generation as of April 16, 2009, and has a nameplate capacity of 15 megawatts or less.</p> |

Table 4-4 Montana REO

2. Conservation & Energy Efficiency Requirements
 - a. The State of Montana has no requirements with respect to energy conservation or energy efficiency.
3. Renewable Energy Requirements
 - a. Basin Electric will not transfer any green tags to any Montana members per the Green Tag Policy.

Nebraska

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|----------|-------------------------------|--|--------------------|
| Nebraska | None | None | N/A |

Table 4-5 Nebraska REO

2. Conservation & Energy Efficiency Requirements

- a. The State of Nebraska has no requirements with respect to energy conservation or energy efficiency.

3. Renewable Energy Requirements:

- a. At this time, Nebraska does not have any renewable energy reporting requirements.

New Mexico

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|------------|---|--|--------------------|
| New Mexico | Rural electric distribution cooperatives are required to have renewable energy account for 5% of retail sales in 2015, increasing at a rate of 1% annually until January 1, 2020, at which time the RPS is 10%. | None | N/A |

Table 4-6 New Mexico REO

2. Conservation and Energy Efficiency Requirements

- a. Basin Electric does not have direct sales in New Mexico and there are no conservation or energy efficiency requirements in the state.

3. Renewable Energy Requirements:

- a. Basin Electric does not have direct sales in New Mexico.
- b. The Real cost threshold for cooperatives is 1% of its gross receipts from business transacted in New Mexico for the preceding calendar year. Cooperatives are not required to incur RPS compliance costs above this level.

North Dakota

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|--------------|---|--|--|
| North Dakota | VOLUNTARY OBJECTIVE 10 % by 2015 | None | <p>Eligible Renewable: For purposes of qualifying for the renewable electricity and REO contained in section 49-02-28, electricity, except for electricity generated from a hydroelectric facility with an in-service date before January 1, 2007, and electricity that is not obtained from repowering or efficiency improvements to a hydropower facility existing on August 1, 2007, regardless of the source's in- service date, qualifies for meeting the statewide objective provided that the source meets the requirements of ND PSC's rules for tracking, recording, and verifying renewable energy certificates.</p> <p>Calculation of total Retail Sales: For purposes of calculating the amount of electricity from renewable energy and recycled energy sources needed to meet the REO, a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before January 1, 2007.</p> |

Table 4-7 North Dakota REO

2. Conservation & Energy Efficiency Requirements

- a. The State of North Dakota has no requirements with respect to conservation or energy efficiency.

3. Renewable Energy Requirements

- a. North Dakota law: Chapter 49-02-28 establishes a state renewable and recycled energy objective. The statute provides that "ten percent of all electricity sold at retail within the state by the year 2015 be obtained from renewable energy and recycled energy sources. The objective must be measured by qualifying megawatt-hours delivered at retail or by certificates representing credits purchased and retired to offset non-qualifying retail sales. This objective is voluntary and there is no penalty or sanction for a retail provider of electricity that fails to meet this objective."
- b. Hydro: Chapter 49-02-30 provides that, "a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before January 1, 2007."
- c. Waste Heat: Chapter 49-02-25 provides that, "recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process," may be counted as renewable.

- d. Independent Verification: Chapter 49-02-33 provides that, “Electricity generation applied to the renewable energy and recycled energy objective, as well as certificate purchases and certificate retirements, must be independently verified through a third-party tracking system selected by the public service.”
- e. Reporting Requirements & Time Periods: Chapter 49-02-34 provides that, “Commencing on June 30, 2009, retail providers shall report annually on the provider’s previous calendar year’s energy sales. This report must include information regarding qualifying electricity delivered and renewable energy and recycled energy certificates purchased and retired as a percentage of annual retail sales and a brief narrative report that describes steps taken to meet the objective over time and identifies any challenges or barriers encountered meeting the objective . The last annual report must be made on June 30, 2016. Retail providers shall report to the public service commission, which shall make data and narrative reports publicly available and accessible electronically on the Internet. Distribution cooperatives may aggregate their reporting through generation and transmission (G&T) cooperatives.” At this time, the ND PSC does not require green tags to be retired through M-RETS.

South Dakota

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|--------------|--|---|---|
| South Dakota | VOLUNTAY OBJECTIVE 10 % by 2015 | None but conserved energy qualifies as a renewable energy | Eligible Renewable- new hydro with a nameplate rating of 10 megawatts or less, and hydro in existence on January 1, 2005, with a nameplate rating of 30 megawatts or less. Calculation of total Retail Sales: For purposes of calculating the amount of electricity from renewable energy and recycled energy sources needed to meet the REO, a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before January 1, 2007. |

Table 4-8 South Dakota REO

2. Conservation & Energy Efficiency Requirements

- a. In February 2008, South Dakota enacted legislation (HB 1123) establishing an objective that 10% of all retail electricity sales in the state be obtained from renewable and recycled energy by 2015. In March 2009, this policy was modified by also allowing “conserved energy” to meet the objective. The objective applies to all retail providers of electricity in the state. However, as a voluntary objective (as opposed to a mandatory standard), there are no penalties or sanctions for retail providers that

fail to meet the goal. In the case of conserved energy, the objective will be measured by methods established by the South Dakota Public Utilities Commission (PUC). At this time, the PUC has not established such methods.

3. Renewable Energy Requirements
 - a. South Dakota Law 49-34A-101, “establishes a state renewable and recycled energy objective that ten percent of all electricity sold at retail within the state by the year 2015 be obtained from renewable energy and recycled energy sources . The objective shall be measured by qualifying megawatt-hours delivered at retail or by certificates representing credits purchased and retired to offset non-qualifying retail sales. This objective is voluntary and there is no penalty or sanction for a retail provider of electricity that fails to meet this objective.”
 - b. Hydro: 49-34A-103 South Dakota law provides that, “a retail provider may deduct from its baseline of total retail sales the proportion of electricity obtained from hydroelectric facilities with an in-service date before July 1, 2008.”
 - c. Waste Heat: South Dakota does consider waste heat recycled energy and thus qualifies as renewable electricity.
 - d. Independent Verification: Electricity generation applied to the renewable energy and recycled energy objective, as well as certificate purchases and certificate retirements, must be independently verified through a third-party tracking system selected by the public service.
 - e. Reporting Time Period: 49-34A-105 South Dakota law provides that, “Commencing on July 1, 2009, retail providers shall report annually on the provider’s previous energy sales during the twelve month period ending on the preceding December 30. This report shall include information regarding qualifying electricity delivered and renewable energy and recycled energy certificates purchased and retired as a percentage of annual retail sales and a brief narrative report that describes steps taken to meet the objective over time and identifies any challenges or barriers encountered meeting the objective . The last annual report must be made on December 1, 2017. The commission shall make the data and narrative reports available and accessible to the public on the Internet. The commission shall compile the data obtained from the reports and submit the data to the Legislature by the following January 1. A distribution cooperative may aggregate its reporting through generation and transmission (G&T) cooperatives.”

Wyoming

1. State Summary

| | Renewable Energy Requirements | Conservation/ Energy Efficiency requirements | Treatment of Hydro |
|---------|-------------------------------|--|--------------------|
| Wyoming | None | None | N/A |

Table 4-9 Wyoming REO

2. Conservation & Energy Efficiency Requirements
 - a. The State of Wyoming has no requirements with respect to conservation or energy efficiency.
3. Renewable Energy Requirements
 - a. At this time, Wyoming does not have any renewable energy reporting requirements.

Basin Electric Portfolio Compared to REOs

Figure 4-1 shows the magnitude of renewable generation needed to meet voluntary and mandated state REO requirements.

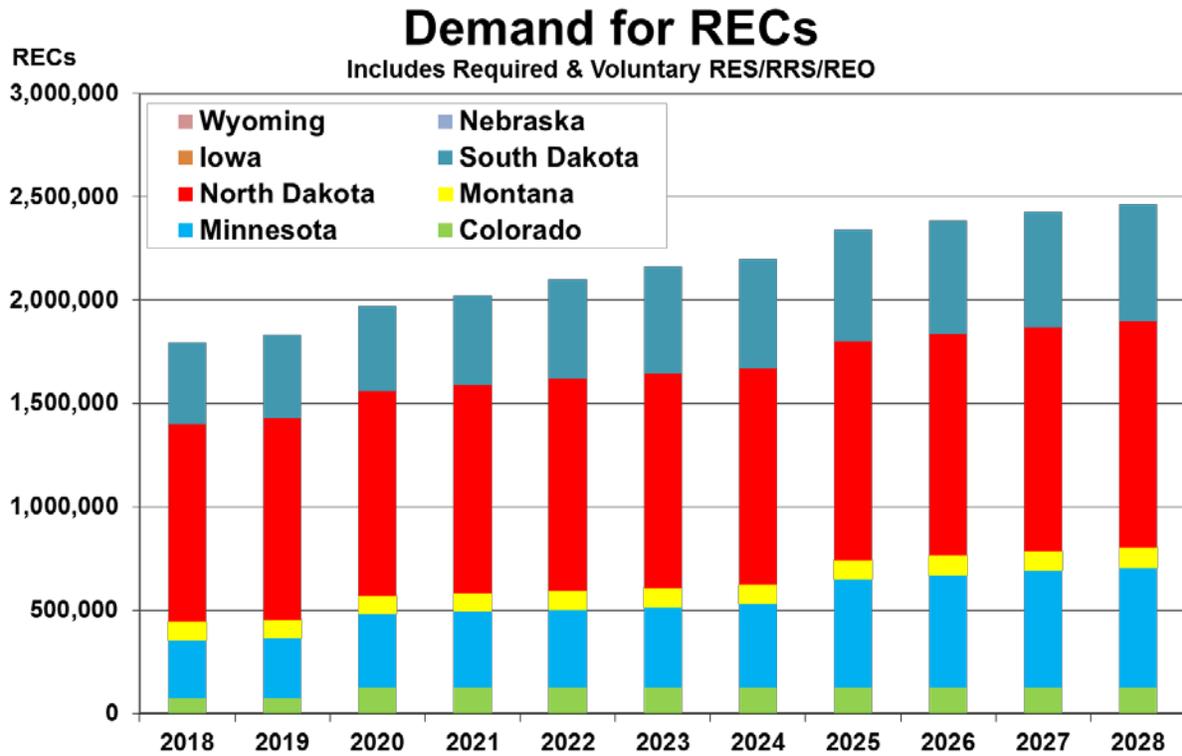


Figure 4-1 REO Requirements by State (MWh)

Figure 4-2 compares the voluntary and mandated state REO requirements to Basin Electric’s current renewable generation portfolio.

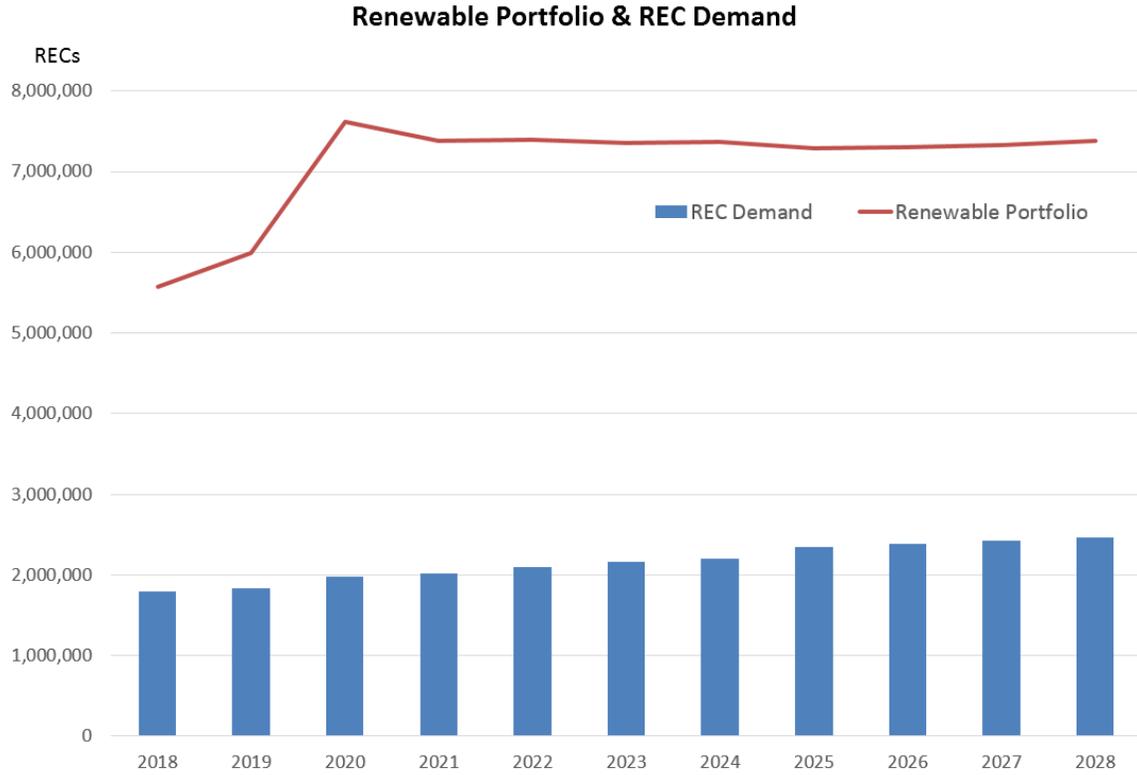


Figure 4-2 REO Requirements and Current Renewable Generation Portfolio (MWh)

Basin Electric and its members have always met all the REO requirements for those states that currently have such requirements and will continue to work with the members on small renewable generation purchases within Basin Electric’s system.

Resource Procurement Activities since the Last IRP

Basin Electric has issued Request for Proposals (RFP) several times over the last number of years (2013 - 2017) to find options for fulfilling power supply obligations. During these years, Basin Electric has successfully negotiated and signed multiple contracts through the RFP process. Such an RFP process is utilized to optimize Basin Electric's system across 9 states and multiple different balancing areas. There have been various proposals including: wind, solar, intermediate, peaking and baseload power proposals provided through these RFPs.

In 2013, we received 73 responses totaling over 10,600 MW. Of these, 21 proposals or 2,669 MW were shortlisted for further analysis. After negotiations, three wind power purchase agreements were executed along with one capacity purchase.

In 2014, there wasn't a formal RFP process. After reviewing some unsolicited proposals, two wind power purchase agreements were executed along with three capacity purchases.

In 2015, we received 18 responses totaling 1,354 MW. Of these, 11 proposals or 641 MW were shortlisted for further analysis. After negotiations, one wind power purchase agreement was executed along with four capacity purchases.

In 2016, we received 85 responses totaling 9,041 MW. Of these, 15 proposals or 1,855 MW were shortlisted for further analysis. After negotiations, one wind power purchase agreement was executed along with four capacity purchases.

In 2017, we received 75 responses totaling 10,613 MW. Of these, 4 proposals or 785 MW were shortlisted for further analysis. After negotiations, two capacity purchases were executed.

5) Transmission Planning

US Transmission System

Figure 5-1 shows Basin Electric's service territory. Basin Electric's service territory includes areas located on both the eastern system and western system. Basin Electric is one of the few utilities that supply electricity on both sides of the national electric system. As a result, there are constraints associated with transfers between Basin Electric's eastern and western service territories.

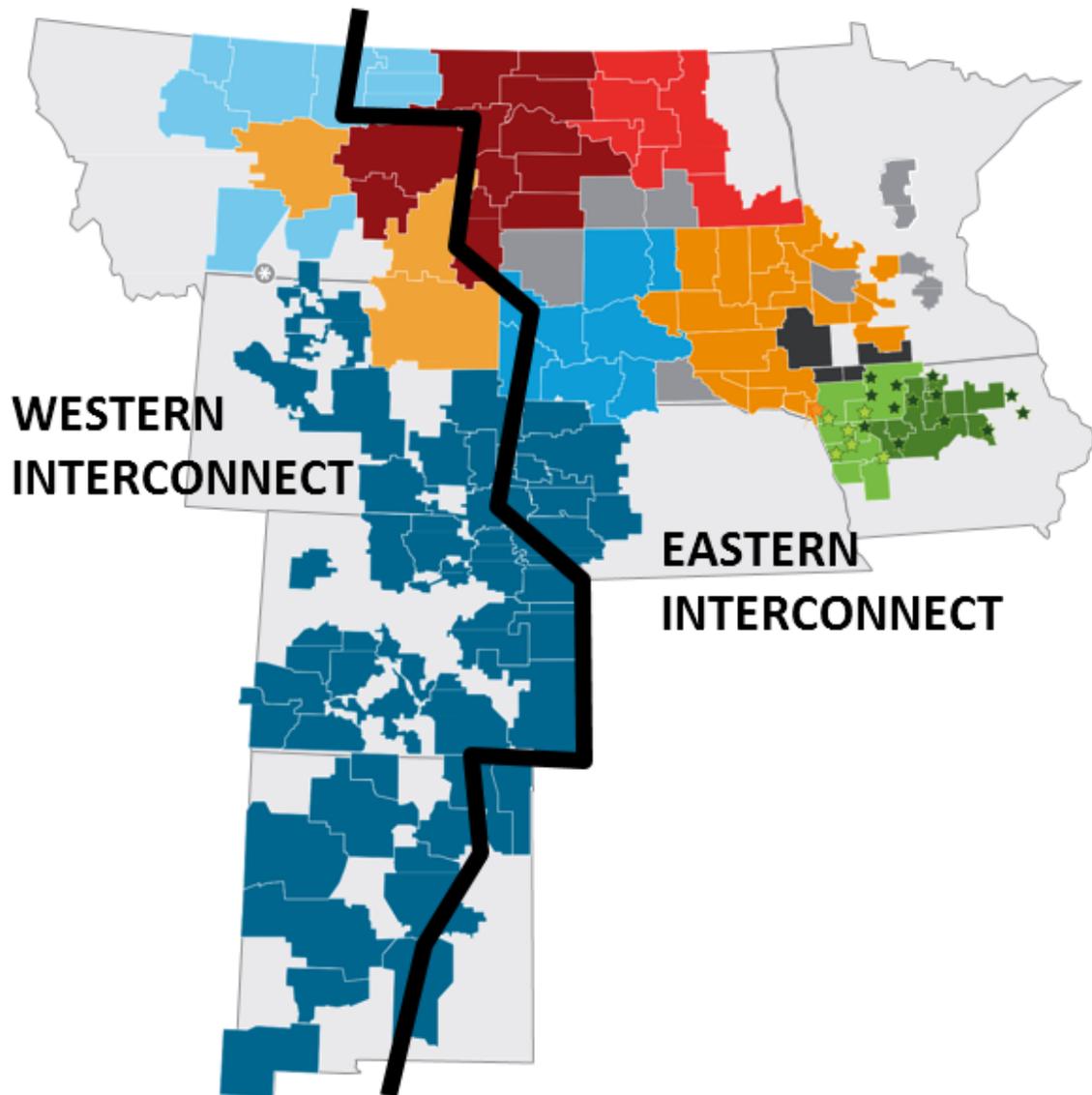


Figure 5-1 Electric System Separation

Direct current (DC) ties, also called interties, bridge the eastern and western national electric system separation by taking alternating current (AC) electricity on one side, converting it to direct current, and then converting it back to alternating current so that it is in sync with the resulting side of the national electric system separation (see Figure 5-2).

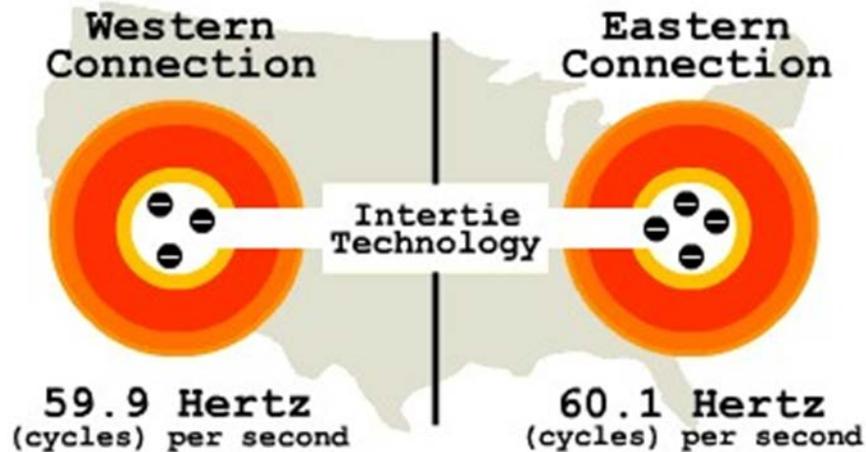


Figure 5-2 Direct Current Ties

Every generator east of the electrical transmission separation drives and affects that system and every generator west of the separation drives and affects that system. The lower load density in the central part of the country as compared to the east and west coastal areas of the United States has resulted in the development of generation being located in the central part of the country with long length high voltage transmission facilities to load centers. This separation of the east and west national grid protects each from the other. A major electrical event on the west will not affect the grid on the east and vice versa. The slightest upset, such as an electric generating unit abruptly separating from the system can change the standard 60 Hertz per second, so the two systems intentionally are not directly connected and synchronized to each other. Connecting the systems would cause several system disconnects because protective devices for the facilities would activate.

Regional Transmission Organization (RTO)

Southwest Power Pool (SPP)

Basin Electric joined the Southwest Power Pool (SPP) RTO in October 2015 as a transmission owning member. SPP oversees the bulk electric grid and wholesale power market in the central United States on behalf of a diverse group of utilities and transmission companies in 14 states. SPP establishes practices for system design, planning, adequacy, regional transmission service tariff, interconnections, operation, reliability, market designs and efficiency, and market power mitigation that will help to assure efficient and reliable power supply among the systems in SPP and SPP transmission customers. Basin Electric participates on various committees and work groups as a function of SPP.

In joining SPP, Basin Electric retains ownership of its transmission and generating assets. Basin Electric's integration into SPP is the culmination of years of discussions and public involvement between the former Integrated System (IS) partners, Western Area Power Administration (Western), Heartland Consumers Power

District (HCPD), our members, SPP, and FERC. Following the transition, the IS became the 19th transmission rate zone within SPP, and is referred to as the Upper Missouri Zone (UMZ).

The SPP assessment area footprint has approximately 61,000 miles of transmission lines, and 4,811 transmission-class substations. The 10-year assessment (ITP10) focuses on facilities 100kV and above to meet the system needs over a 10-year horizon. Along with the highway/byway cost allocation methodology, the ITP process promotes transmission investment that will meet reliability, economic, and public policy needs intended to create a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources.

Basin Electric serves load in Zone 19 and Zone 17 of the SPP transmission system. Zone 19, also known as the Upper Missouri Zone (UMZ) is comprised of 19 transmission owners with an annual revenue requirement of nearly \$280 Million. Zone 17, also known as the NPPD zone, is comprised of three transmission owners with an annual revenue requirement of \$50 Million. Figure 5-3 shows the SPP RTO Footprint in August of 2018.

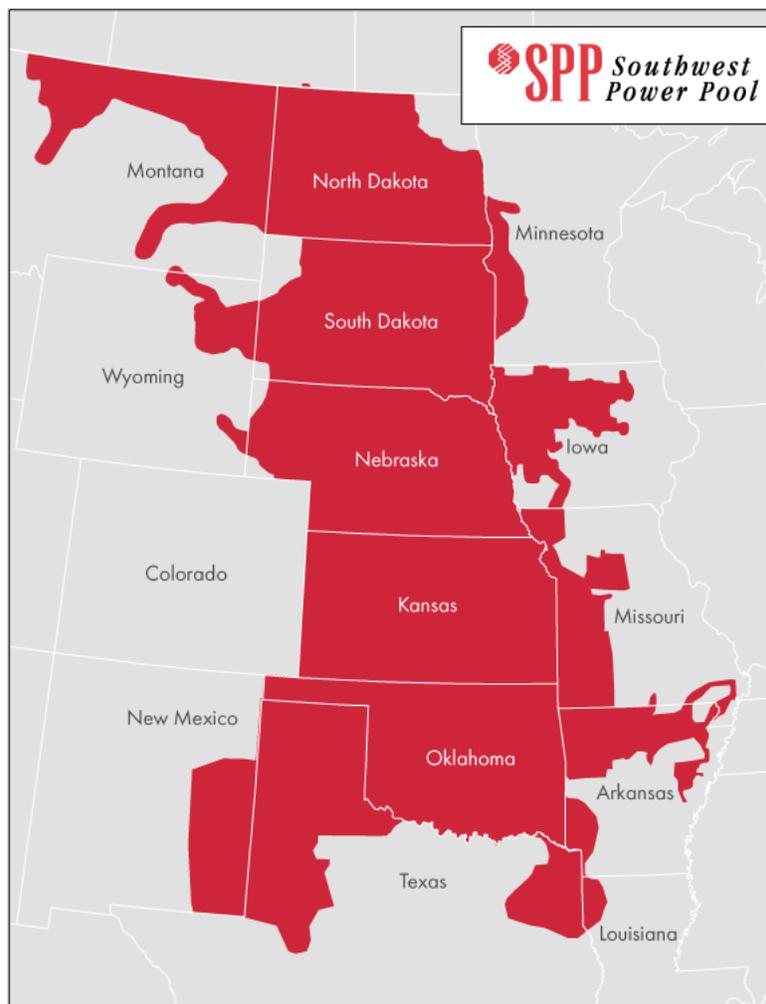


Figure 5-3 SPP RTO Footprint (August 2018)²

² (SPP Website, 2018)

Midcontinent Independent System Operator (MISO)

MISO manages approximately 65,000 miles of high-voltage transmission and 200,000 megawatts of power-generating resources across its footprint.

The MISO Transmission Expansion Plan (MTEP) proposes transmission projects to maintain a reliable electric grid. Major categories of the MTEP 2018³ include the following: A total of 85 baseline reliability projects required to meet North American Electric Reliability Corporation (NERC) reliability standards, 16 generator interconnection projects required to reliably connect new generation to the transmission grid, 2 transmission deliverability service projects that includes network upgrades driven by transmission service requests and 340 other projects based on local Transmission Owner needs including reliability, economics, equipment age and condition, environmental, etc.

Basin Electric’s members have loads that reside on seven transmission owners systems in MISO Local Resource Zones 1 and 3. These transmission owners include OTP, NSP, MDU, MP, MEC, ALTW, and GRE.

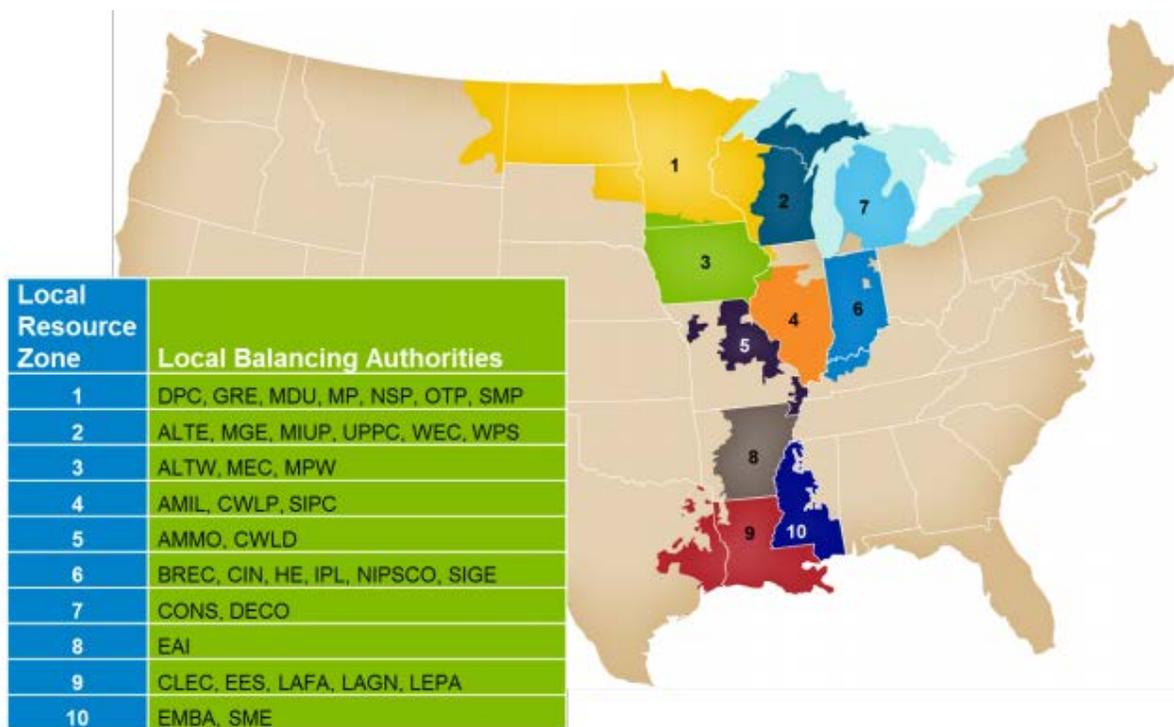


Figure 5-4 MISO Transmission Zones⁴

Potential West Side RTO

The Mountain West Transmission Group (Mountain West) is an informal collaboration of electricity service providers that are working to develop strategies to adapt to the changing electric industry. The group was formed in early 2013 to evaluate an array of options ranging from a common transmission tariff to regional transmission organization (RTO) membership. Based on the results of extensive evaluations, Mountain West decided to focus its attention on full membership in an existing RTO.

³ (MTEP 2018 Review, 2018)

⁴ (NERC Probabilistic Assessment MISO, 2016)

In April of 2018 and later that year the Public Service Company of Colorado and Black Hills Energy respectively chose to withdraw from the initiative. Following this news the other members decided to place the initiative on hold and place their efforts in implementing SPP as the Reliability Coordinator. This initiative continues to be on hold until the implementation of SPP Reliability Coordinator begins January 1, 2019.⁵

Other Transmission Areas

Outside of the SPP and MISO RTOs, Basin Electric has loads, resources, and transmission facilities in the Western Electricity Coordinating Council's (WECC) Rocky Mountain Reserve Sharing Group (RMRG) and Northwestern Power Pool (NWPP) sub-regions in the Western Interconnection. The Western Interconnection is a wide area power grid that runs from western Canada to Baja California in Mexico, and from the Great Plains to the Pacific Ocean.

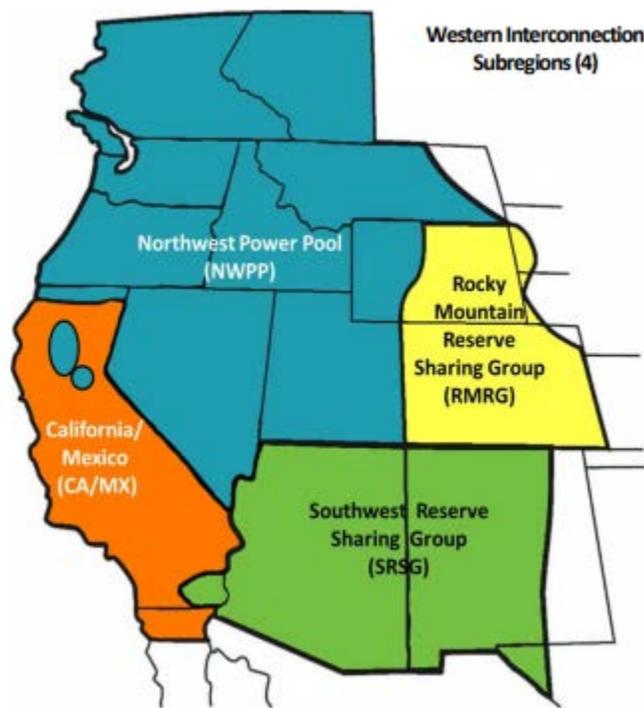


Figure 5-5 WECC Interconnection Sub-regions⁶

⁵ (WAPA MWTG Initiative, 2018)

⁶ (WECC LAR Methods and Assumptions, 2014)

SPP will begin offering Reliability Coordination (RC) services in the Western Interconnection in late 2019. SPP has indicated its intent to serve as an RC in the west in letters to WECC and NERC. Figure 5-6 shows the potential footprint of the RC services provided in the western interconnection.

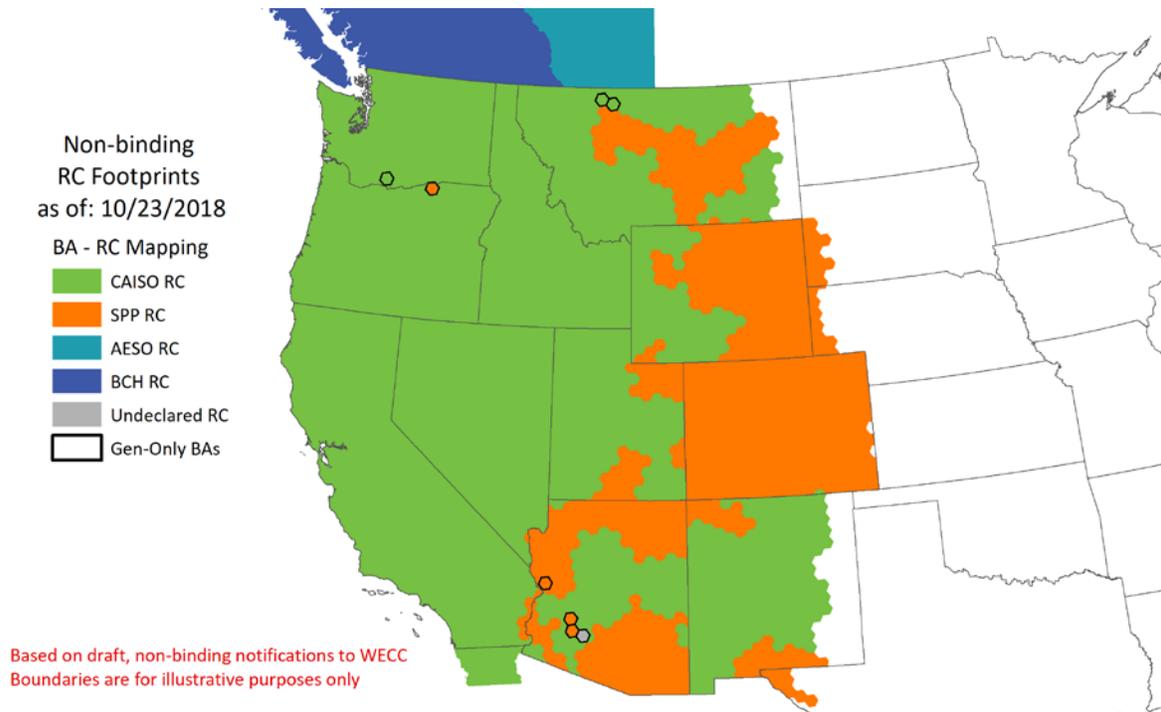


Figure 5-6 Draft, Non-binding RC Footprints in WECC Interconnection as of 10/2018⁷

WECC-RMRG Transmission

Transmission facilities in NWPP are planned in accordance with NERC and WECC planning standards. Those standards establish performance levels intended to limit the adverse effects of each system’s operation on others and recommend that each system provide sufficient transmission capability to serve its customers, accommodate planned inter-area power transfers and meet its transmission obligation to others.

In the RMRG sub-region of WECC, Basin Electric participates in the Common Use System (CUS) with Black Hills Energy and Powder River Energy Corporation (PRECorp). The CUS is located in Western South Dakota and Eastern Wyoming.

Basin Electric also participates in the Missouri Basin Power Project (MBPP) with Tri-State Generation and Transmission (TSGT) and Heartland Consumers Power District. The MBPP is located in Southeastern Wyoming, Northern Colorado, and Western Colorado. The transmission system facilities are located on the Eastern Interconnection and Western Interconnection.

Basin Electric is a transmission customer of Western Area Power Administration - Loveland Area Project and PacifiCorp’s transmission systems to reach load obligations in Wyoming and Montana.

⁷ (WECC Draft RC Footprints, 2018)

WECC-NWPP Transmission

Transmission facilities in NWPP are planned in accordance with NERC and WECC planning standards. Those standards establish performance levels intended to limit the adverse effects of each system’s operation on others and recommend that each system provide sufficient transmission capability to serve its customers, accommodate planned inter-area power transfers and meet its transmission obligation to others.

Basin Electric is a transmission customer of the NorthWestern Energy and the SPP Upper Missouri Zone (UMZ) transmission systems which the western interconnect transmission facilities are owned by Western’s Upper Great Plains Region to reach load obligations in Montana.

Owned Transmission Facilities

Basin Electric owns transmission facilities in multiple systems including primarily SPP, the CUS, and the MBPP system, among others.

Table 5-1 specifies the number of miles of transmission lines that Basin Electric owns in the various transmission systems.

| System | Joint Ownership | Total Circuit Miles | BEPC Owned |
|-----------------------------|---|----------------------------|-------------------|
| SPP | SPP Members | >60,000 | 1809 |
| Common Use System | Basin Electric, Black Hills, Members 1st | 1056 | 279 |
| MBPP System | Basin Electric, Tri-State, WMPA, MRES, HCPD, Lincoln Electric | 681 | 288 |
| Other | | 0 | 43 |
| Basin Electric Total | | | 2419 |

Table 5-1 Basin Electric Transmission

Power Supply Planning Areas

Basin Electric has member loads in the following Balancing Authority regions: Midcontinent ISO (MISO), Southwest Power Pool (SPP), PacifiCorp East (PACE), Western Area Power Administration Upper Great Plains Region West (WAUW), NorthWestern (NWMT) and Western Area Colorado Missouri (WACM).

These regions are used in Basin Electric's internal power supply modeling. Load obligations are served by generation either directly within each area or by moving power between areas in an attempt to optimize the complete system. The capabilities to move power from one region to the next is based on transmission constraints that are modeled between each planning region. Movement from the east to the west, or vice versa, is determined by the DC tie capacity to which Basin Electric has rights. Figure 5-7 shows Basin Electric's service territory broken up into these four distinct planning regions.

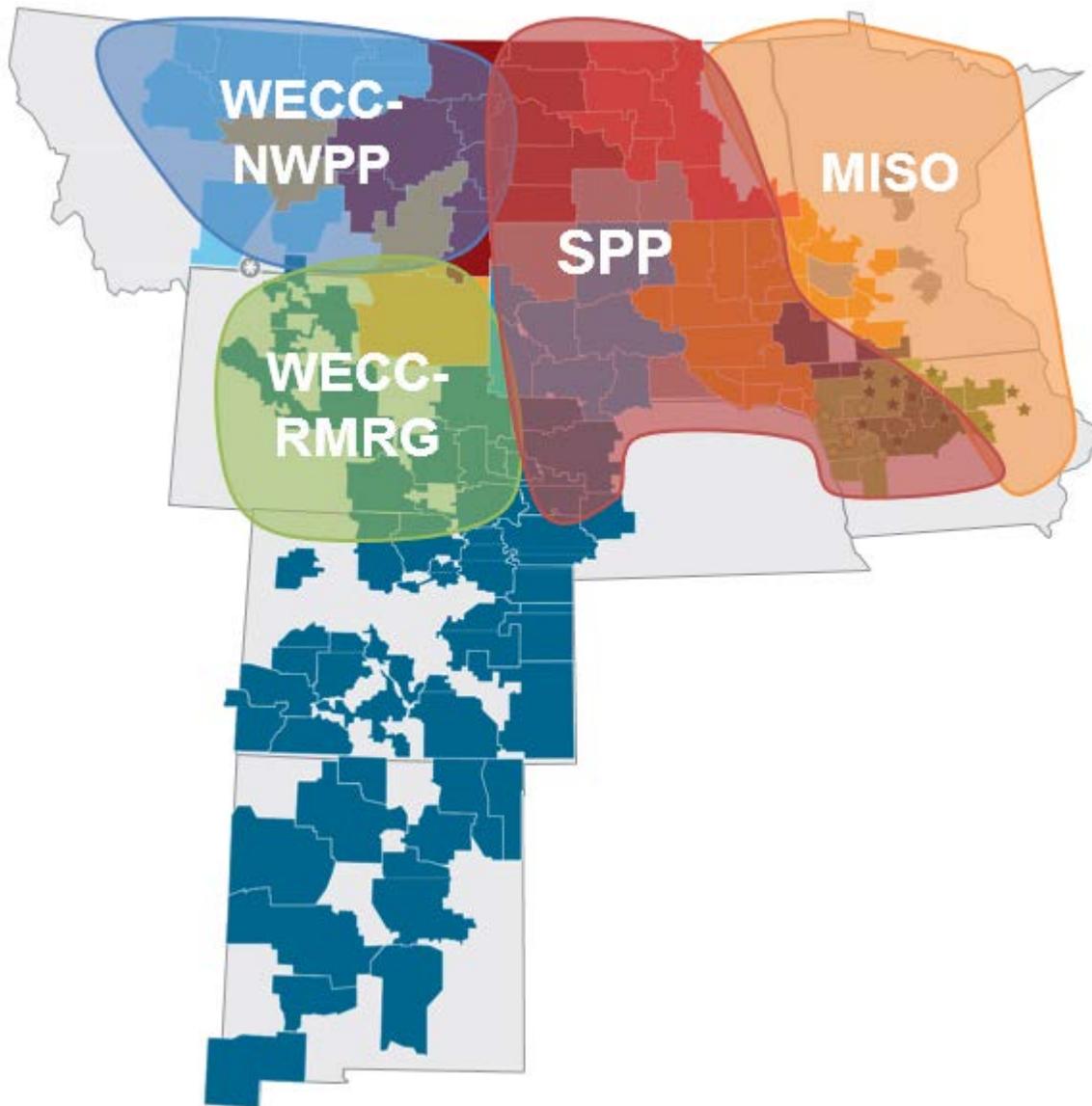


Figure 5-7 Map of Basin Electric's Service Territory and Power Supply Planning Regions

Figure 5-8 shows all of the DC tie locations in the United States, where today Basin Electric has rights to move power across the Miles City, Rapid City, and Stegall DC ties.

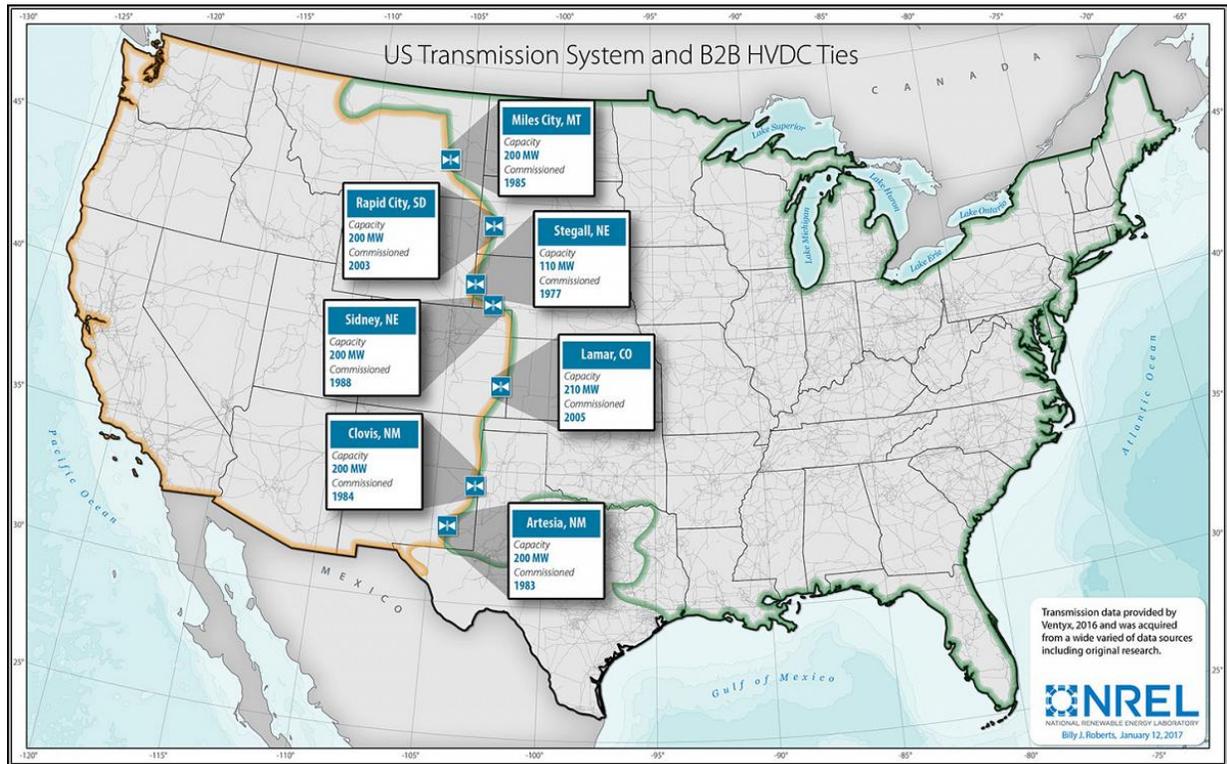


Figure 5-8 NREL Map of U.S. Transmission System and B2B HVDC Ties⁸

Basin Electric has access to several DC ties that bridge the connections of the national electric system. In total, Basin Electric has ownership or capacity rights to transfer 240 MW in the west-to-east direction and 423 MW in the east-to-west direction, as shown in Table 5-2 DC Tie Capacity, Ownership, and Rights

| DC Tie | Capacity (MW) | BEPC % Ownership | BEPC Rights (MW) |
|-------------------|---------------|----------------------|----------------------|
| Miles City DC Tie | 200 | 40% | 183 (east→west only) |
| Stegall DC Tie | 110 | 0% (Tri-State Owned) | 110 (bi-directional) |
| Rapid City DC Tie | 200 | 65% | 130 (bi-directional) |

Table 5-2 DC Tie Capacity, Ownership, and Rights

⁸ (NREL Interconnection Seams Study, 2017)

6) Load and Resource Balance

Introduction

The load forecasts for each electric cooperative is developed every year in coordination with the local distribution cooperative and its respective Class A G&T. Each individual local distribution member's staff and management review and approves their forecast. After local distribution approval, the Class A G&Ts roll up their members forecasts and have their Board approve the G&T forecast. This load forecast is then brought to Basin Electric Board for approval, at which point Basin Electric uses this load forecast in Basin Electric's power supply planning, transmission planning, financial forecasting, and rate setting processes.

This chapter provides further details into Basin Electric's load forecasts as well as how they are used for power supply planning on a capacity and energy basis.

Load Forecast

Load Forecast Preparation

Basin Electric's primary mission is to provide electrical power to its member-owners. In order to accomplish this objective, the cooperatives must understand how the consumers are presently using their electricity and must forecast the consumers' future electrical requirements. The projection of future requirements serves as one of the main planning tools in determining the cooperative's future operating strategy. Adequate resources and transmission facilities must be maintained and, where necessary, developed to deliver the required power to the members.

Two major studies are jointly prepared by the members and Basin Electric to address where the members are presently using their power (end use survey) and how much they will require in the future (load forecast). These studies are prepared in accordance with the Rural Utilities Service (RUS) general guidelines. Both the end use survey and the load forecast represent a joint effort by the distribution cooperatives, the G&T Cooperatives, and Basin Electric. In order to assure all segments of the cooperative's structure are involved, a Load Forecast Technical Committee was established. This committee consists of representatives from the three tier cooperative structure.

The Load Forecast Technical Committee approved the timetable and procedures used in preparing the 2018 Update to the 2017 Load Forecast (2018 Load Forecast). RUS attendance and participation at the committee meeting provided a forum for the cooperatives and RUS to exchange ideas, discuss problems, and brainstorm ways to improve the process. The 2018 Load Forecast Work Plan was approved by the Basin Electric Board of Directors.

End use surveys and load forecasts are prepared for all Basin Electric members, except Tri-State, which conducts their own studies. Participating members represent cooperatives located in North Dakota, South Dakota, Minnesota, Montana, Iowa and Wyoming. Individual studies are prepared for each participating distribution cooperatives. The distribution cooperative studies are combined to obtain G&T studies and the G&T studies are combined to obtain a Basin Electric report.

The purpose of the load forecast is to provide the distribution cooperatives, the G&T's, and Basin Electric with a forecast of their power supply obligations to their consumer-owners. The load forecast, which is prepared on a distribution cooperative basis, is conducted in accordance with RUS criteria. The criteria defines a load forecast as a thorough study of a cooperative's electric loads and the factors that affect those loads in order to determine as accurately and as practical the cooperative's future requirements for energy

and capacity. The individual member's load forecast analyzes the cooperative's service area for historical and projected developments that have and will influence future load growth.

The 2018 Load Forecast is a weather normalized forecast. While the load forecasting process does an adequate job of predicting energy and average demand usage over a long forecast period, short time frame events can affect peak demands experienced and cause deviations from the predicted peak demands. These short time frame events include significant heat spells, extended cold snaps, and moisture during critical farming periods.

- Heat spells can cause building envelopes to retain heat causing air conditioning to be used for longer periods than expected in the normal weather periods. Less efficient methods of cooling buildings may be used.
- In our service territory, Cold snaps generally occur with significant wind that tends to draw heat out of building envelopes causing electric heating installations to use more peak demand than during normal heating.
- Rain and high humidity events during the harvest season may cause crops to retain moisture. This may lead to mold and disease issues when placed in a bin causing the valuable commodities to be worthless. Recent increases in on-farm grain storage have necessitated the need for the farmers to be able to drop the moisture levels in their grain prior to placing it in a bin. This has led to increases in on-farm air handling and air drying facilities. This load usually occurs during the fall shoulder months of September, October and November. Recently, moist springs and cool damp early summers have pushed crop plantings later into the spring and early summer. This development has pushed the harvest and the subsequent air drying later into October, November, and into December, the start of the heating season. This shift has increased electrical demand causing typically "shoulder" periods, October to December, peaks to increase in recent years.

The use of average weather is acceptable for planning budgets and sales forecasts. However, all of the weather factors detailed above, along with localized issues of access to competing fuels, has increased the demand for electricity past normally expected levels. Prior research using primarily residential systems has indicated that the weather conditions could increase the projected peak demands approximately 10% more than what is stated in this report. This issue poses a challenge for distribution and transmission system planning.

Econometric Models

The basis for econometric modeling is to identify factors in the economy that have historically affected electrical consumption. This is accomplished by using regression analysis software that establishes a mathematical relationship between the economic factors and power usage. The mathematical relationship, which is in the form of algebraic equations, represents the econometric model.

The econometric models are based on regression analysis. Regression analysis is a statistical technique used to identify a relationship between an observed event and other measured events that can be shown to be related. These are known as the dependent and the independent variables, respectively.

Independent variables must be applicable to the members' service territory and be of importance to the local economy. This is the first step to ensure the model will accurately explain the historical trends. This gives the confidence that the same factors that have influenced previous trends will accurately reflect future expectations.

The next step to determine if the model is acceptable is the combination of the statistical results of the model. The model statistics include the R-squared, adjusted R-squared, and basic statistical information. The R-squared indicates the amount of variation of the dependent variable explained by the independent variables. To show the impact of changes in the number of independent variables used in a model, an adjusted R-squared is used; therefore, the explained variation can be compared with the same dependent variable and different numbers of independent variables.

The statistical significance of the explanatory variables used in the model is measured by a t-statistic. A T-statistic (ignoring negative signs) of at least 2.0 would be required for a 95 percent level of confidence and 1.5 for a 90 percent level of confidence, depending upon the number of observations and variables used in the model.

The Durbin-Watson test examines the equation residuals that are the differences between the fitted and the actual historical values. In a good model the residuals are randomly distributed and are of approximately constant magnitude. This indicates the model has explained all of the patterns in the data. In general, a Durbin-Watson near 2.00 indicates the absence of autocorrelation.

When residuals are not randomly distributed, a Cochrane-Orcutt transformation (AR term) can be computed to develop an equation that does have randomly distributed residuals. After the variables are transformed by adjusting the equation according to the value of the AR term, a new equation is developed.

The combination of the variables selected, model statistics, and the forecasted results all are considered together to determine the validity of the forecast.

Econometric models are used for the majority of the member systems to forecast residential sales. In most instances, two residential econometric models are developed for each cooperative. The first model relates the number of historical residential consumers to factors that have been shown to influence their numbers in the past. The second model is developed for the average annual usage per residential consumer. Multiplying the forecasts of these two models developed the total residential energy forecast.

The small commercial modeling and other smaller consumer sectors are developed using econometric or trending models. In some cases they may also be judgmental forecasts or a combination of the three.

The distribution member forecasts are forecasts of annual energy requirements by category. To translate the annual energy requirements into monthly energy and demand needs, two econometric models were developed to distribute this correctly. The first model uses historical monthly energy purchases along with actual weather patterns to determine the monthly per unit purchase pattern. This purchase pattern is applied to the annual energy forecast to develop a monthly energy forecast. The second model was used to develop a monthly demand forecast where an econometric model is fitted through the historical load factors. The resultant load factor pattern is applied to the monthly energy forecast to determine the monthly demand forecast.

Explanatory Variables

The economy of the upper Midwest has fared the recent nationwide economic downturn quite well, due to the relative strength of the agricultural economy and energy exploration. Employment in the Basin Electric territory, for the most part, has not seen the major swings that other areas of the country have. Due to a diverse economy that is not centered in a singular industry these strong historical employment trends are expected to continue into the future. The following graph indicates the average unemployment rates for the last 12 months with the Basin Electric cooperative service territory overlaid, and shows the relative strength of the economy in the upper Midwest.

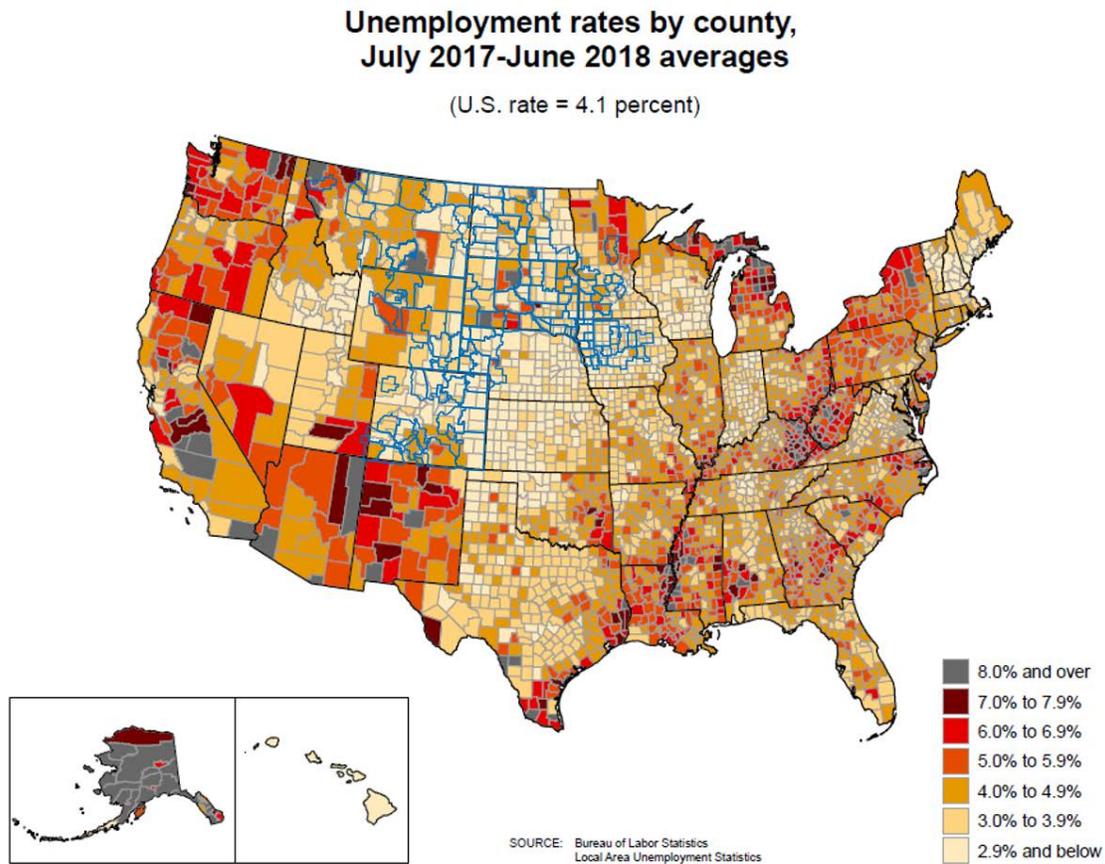


Figure 6-1 Unemployment Rates by County

The major sources of the explanatory variables are as follows:

Historical data for county and metropolitan statistical area (MSA) level employment, population, earnings and income is provided by the U.S. Department of Commerce Bureau of Economic Analysis (BEA) and the Census Bureau. The state and federal governments monitor the data closely as it serves as a measure of the state of the local economies.

An entire set of historical and forecast employment data was used from Woods & Poole Economics, Inc. (W&P). W&P is an econometric forecasting firm that provides projections for employment, earnings, income, and population on a county and MSA basis. W&P used BEA data through year 2016. The exception to this is

the population data, where W&P data was updated to include the 2017 data available from the US Census Bureau.

W&P is used as sources for the economic and demographic historical and forecasted county data. IHS Global Insight is used for county, metro, state and national economic data.

Historical & projected agricultural production and price data was obtained from the United States Department of Agriculture (USDA) and additional forecasted data was obtained from the Food and Agricultural Policy Research Institute (FAPRI) 2018 U.S. Baseline, as well as the USDA baseline agricultural projections. FAPRI specializes in agricultural research and forecasting.

The FAPRI baseline projection used is a result of a three-step process. It begins with macroeconomic assumptions for the U.S. Developed by IHS Global Insight. The assumptions are used to develop a FAPRI preliminary baseline, which is then distributed to a group of reviewers. The reviewers critique and comment on the validity of the assumptions and the baseline projection. After receiving comments, the baseline projection is revised and finalized.

The FAPRI baseline developed includes the assumptions that government laws or policies remain unchanged, that normal weather occurs, and that random events such as droughts, diseases, and floods do not occur.

The FAPRI and the USDA historical and projected data are used for forecasting some of the residential service areas where farming and ranching have a big influence.

The majority of the members' consumers are engaged in farming/ranching and agriculture. In most of the states the members serve, farming/ranching and agriculture is first in new wealth creation.

Since agriculture is the dominant industry in most of the areas our members serve, agricultural explanatory variables have been heavily incorporated into the econometric models. In the 2018 Load Forecast, agricultural explanatory variables included: national beef production and average prices, national corn production and average prices, national wheat production and average prices, national hog production and average prices, along with county level production of selected agricultural variables.

Other demographic and economic variables used in the 2018 Forecast included:

- Population
- Households
- Total Employment
- Farm Earnings
- Transfer Payments
- Total Personal Income
- Farm Employment

The forecasts for these variables, which are available on a county basis, were obtained from both W&P and IHS Global Insight.

Another major consideration in the load forecast econometric modeling is the competition between electricity and alternate fuels. This competition occurs in space heating, water heating, cooking, clothes drying, and grain drying. The future price of alternate fuels and how they compare with the distribution cooperative's electricity prices affects electric consumption.

Historical alternative fuel prices are obtained on a state level from the DOE's, State Energy Data 2016 Price, Consumption and Expenditures Data (SEDS). Basin Electric uses DOE projections of regional price forecasts to develop projections of alternative fuel prices. A further explanation can be found in the ratio variable narrative in the residential energy use per consumer section.

IHS CERA is used for natural gas and oil prices for the energy related loads. Wood Mackenzie, IHS, and DOE data are also used in the energy related sectors.

Projected electricity prices were obtained from the distribution cooperative's financial forecast. The econometric models address the competition between electricity and alternate fuels by including a ratio computed by dividing electricity costs by the predominant alternate fuel cost in each member's service territory. The ratio is a weighted average of alternate fuels used by the residential consumers for their primary heating system, as indicated by the cooperative's end use survey. In order to compare the energy alternatives on a uniform basis, the alternate fuel and electricity prices are converted to real dollars on a per million British thermal unit (Btu) basis.

Weather has a significant effect on the cooperative's energy requirements due to energy uses such as heating, grain drying, and air conditioning. In order to address these effects, the econometric models normally include either heating degree days, cooling degree days, or a combination of both. Historical heating and cooling degree day's weather data was obtained from the National Oceanic and Atmospheric Administration (NOAA). This information is received for first-order stations, as well as all cooperative stations within the geographic region. Forecasts for weather data are assumed to be the simple average of 2001-2016 values.

Inflation Indexes

For the 2018 Forecast there are three inflation indexes used to deflate historical data and the same to project future inflation. These indexes or deflators use the base 2016 equals 100. Those three indexes include:

Producer Price Index (PPI) (all commodities): This index is used to deflate crude oil prices. Real 2016 dollar crude oil prices are used as a variable in the oil related models and forecasts and also in residential models in oil producing areas. The forecast for the PPI is obtained from the Energy Information Administration's 2018 Annual Energy Outlook (AEO).

Gross Domestic Product - Implicit Price Deflator (GDP-IPD): This index is used to deflate all agricultural monetary data from FAPRI to real 2016 dollars. The forecast is obtained from the Congressional Budget Office.

Personal Consumptions Expenditures - Implicit Price Deflator (PCE-IPD): This index is also obtained from the Congressional Budget Office. This implicit price deflator is used to deflate all non-FAPRI monetary data other than that covered by GDP-IPD and PPI to real 2016 dollars. This index is used to deflate such data as electricity prices, alternative fuels, personal income and earnings. Also, it is used to convert current prime interest rates to real prime interest rates.

In addition to the previously mentioned forecast variables, there is a tremendous array of commercial projects being monitored for their impacts on Basin Electric's wholesale energy sales. These industries are oil, coal, coal bed methane (CBM), ethanol, and bio-diesel related. Each of these categories is discussed in detail below.

Load Forecast Sectors

In 2016 Basin Electric's membership sold 29% of their energy to the residential sector. The large and small commercial represented 21% and 12% of sales respectively. The other 38% of sales were spread among the remaining sectors.

2016 Annual Energy Needs

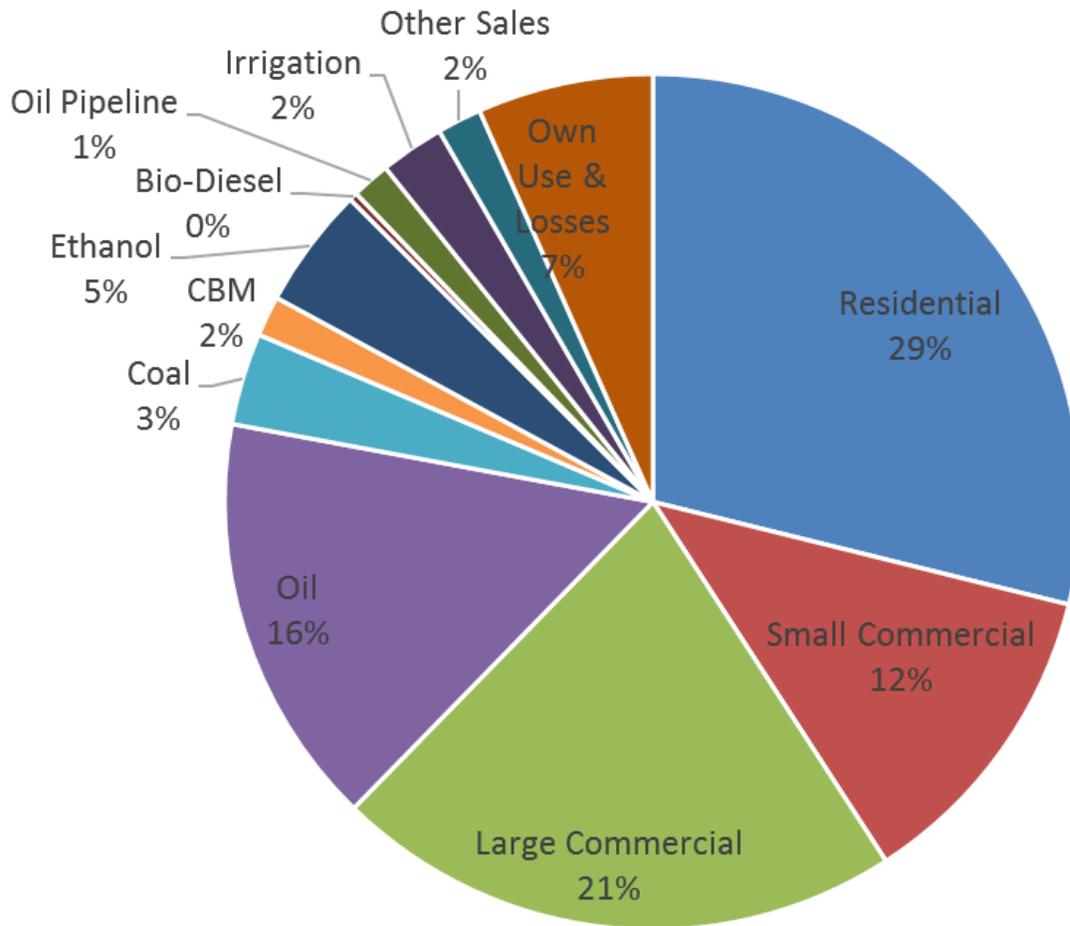


Figure 6-2 2016 Total Member Requirements by Sector

For the remainder of this section, we will discuss each sector in detail.

Residential Forecasts

The load forecast continues to concentrate on the residential classification since it represents a large portion of the energy sales for Basin Electric. The residential energy forecasts are prepared by (i) forecasting the number of residential consumers; (ii) forecasting the average annual energy consumption per residential consumer; and (iii) multiplying the two forecasts together to obtain a total residential sector energy forecast. All load forecasts are net of demand side management.

The starting point in the forecasting process is to develop historical databases for each distribution cooperative. These databases contain information on the member's monthly energy sales by consumer classification. They also provide data on the cooperative's own use and losses, and data on their monthly demand and energy wholesale power purchases. The databases are developed annually from the information the members report to RUS on Form 7 or its equivalent. The data is updated and modified to reflect reclassifications that occasionally occur between consumer categories at the distribution cooperative. These reclassifications may result from changes in the cooperative's rate structure or the size criteria of different rate categories.

Subsequent to the completion of the historical database development, regression analysis software is used to identify economic, demographic, and meteorological factors that have affected the member's power requirements. These factors are called explanatory variables as they explain why the electric requirements change. While the explanatory variables are first used to develop the econometric models based on historic relationships, the variables are also used to develop the forecasts that require historical and forecasted values.

Small Commercial

The small commercial classification consists of commercial accounts that are generally 1,000 kVA or less. This section addresses the econometric models that forecast the small commercial consumers and energy use. The models developed took into consideration the historical factors that statistically, demographically, and economically influenced each member's number of small commercial consumers and small commercial energy use.

The make-up of the small commercial accounts is generally larger farms, small retail and wholesale establishments and other types of accounts that do not qualify for residential status. It has been observed that the small commercial sector closely mirrors the cooperatives local and regional economy. Therefore, the small commercial sector is generally modeled using the same type of variables that are used in the residential modeling.

Large Commercial

The large commercial classification consists of commercial accounts that are generally 1,000 kVA or larger. The types of businesses that are included in this classification are generally manufacturing, large retail, and processing facilities. These types of businesses do not necessarily mirror the local economy. The factors that drive these accounts usually have national impacts. Therefore, we use national macroeconomic variables to determine annual energy usage.

Oil-Related Commercial Forecast

The service territory of Basin Electric's members in Western North Dakota, Eastern Montana, and Northwest South Dakota lies within a geological formation known as the Williston Basin. In addition to the Williston Basin, Basin Electric also provides wholesale electricity to the Powder River Basin (PRB) in Northeastern Wyoming, which also produces a considerable amount of oil. Significant oil related commercial load growth is not anticipated in the PRB, therefore, the rest of this section deals with the Williston Basin.

The small and large commercial loads of those members that serve in the shale oil production areas of the basin are heavily influenced by oil and gas exploration, production and distribution activities. Direct loads, such as oil pumps, pipelines, compressors and processing plants contribute directly to the amount of commercial load. Other commercial loads, such as support services, are indirectly related to oil activity as they would not exist without the oil exploration, development and extraction activities.

For those members whose commercial loads are heavily influenced by oil activities, three tier econometric models were developed to project their commercial loads.

The econometric models generally consist of three models for each distribution cooperative. They generally address new oil production, oil prices, and number of commercial consumers, total commercial energy, and other factors. New upcoming oil projects and services are also included.

The most important variable in the determination of oil production and related loads is crude oil prices. The crude oil price used in the models is the domestic refiner's acquisition cost of crude oil, which represents an average cost the domestic refiners pay for their crude oil.

Oil loads have been somewhat cyclical in the past. This was mainly due to oil price volatility. Domestic oil prices are largely influenced by international oil markets, which are influenced by sometimes radical conditions and unstable situations. Oil prices are also significantly influenced by radical weather conditions such as the hurricanes occurring in the Gulf of Mexico. Oil prices are also influenced by national and international demand, the value of natural gas, and the value of the U.S. dollar. In recent years, developing India and China economies have been identified as very significant users of oil and hence putting upward pressure on oil prices.

Coal-Related Commercial Forecast

The service territory for the coal production of Basin Electric members is located in Wyoming, Montana, and Western North Dakota. Generally, this region is considered by the Energy Information Administration as Western coal production in the United States, which had grown steadily since 1970 to 2006 and has recently begun to decrease. The majority of this Western coal production occurs in Wyoming and Montana in the coal fields referred to as the Powder River Basin (PRB), which includes the Northern PRB (in Montana) and the Southern PRB (in Wyoming). North Dakota coal production comes from Lignite mines that are located in Central North Dakota. Almost all of this lignite is used for power generation locally.

According to the Energy Information Agency (EIA), Wyoming has been the largest coal producing state for many years. In 2016, Wyoming produced 297 million short tons of coal.

Econometric forecasts are developed for the coal related portion of the small and large commercial sector for the PRB in Wyoming. These forecasts are derived by the use of econometric models, as well as upcoming coal projects and services.

The coal production and energy forecasts for Western North Dakota's coal fields are judgmental forecasts based on the estimated production of the mines located in Mercer County that supply Basin Electric's Antelope Valley Station, the Leland Olds Station, and the Dakota Gasification Company.

Any coal related commercial forecasts must include an analysis of the uncertainty of the future of coal generation in the U.S. As the cost of Natural Gas has remained at a lower price and the possibility of future carbon legislation looms, more coal-based generation is being retired and the combination of Natural Gas

and renewable resource generation are becoming a bigger part of the generation mix. This paradigm shift will impact coal production in the U.S., and therefore affect Basin Electric's member's loads.

Coal Bed Methane Load

This load is related to the extraction of methane gas that is trapped in the sub-bituminous coal reserves located within one of Basin Electric's member service territory. Due to the increase of extensive shale drilling in the United States, higher cost coal bed methane natural gas has been relegated to a niche play, and significant growth is not expected in this sector.

Ethanol and Bio-Diesel Related Commercial Load

The ethanol sector loads were judgmentally projected by the distribution members that have had contact with the companies planning new plants or expansion of existing facilities. No new facilities are expected during the forecast period.

Pipeline Related Commercial Load

The pipeline sector loads are judgmental projections that Basin Electric's members provide. TransCanada's Keystone XL has been included in the projections for the 2018 Forecast.

Other retail sectors that are considered when compiling the distribution forecasts follow.

Other Commercial Load Forecasts

Those commercial loads that are not oil or coal related are generally prepared using trending and sometimes judgmental forecasts. These forecasts that consider past trends and expected future developments reflect the knowledge and expertise the local cooperatives have of their service territories.

Irrigation

Irrigation sales fluctuate during the historical periods due to the weather, the state of the farm economy, and government programs. Trending models were used to forecast consumers and energy.

Other Sales

These represent sales to categories such as Public Street and highway, public authorities, and other RUS borrowers. These sales, which are usually quite small, are forecasted using trending models.

Losses

The forecasted sales for each of the previous consumer categories are on an at-load basis, meaning the sales represent the amount of power delivered to the retail consumers. One of the objectives of the load forecast process is to obtain a forecast of the distribution cooperative's wholesale power requirements at its substations. These requirements, which correspond to their purchases, are obtained by increasing the distribution cooperative sales to reflect their own use, as well as system losses occurring on its transmission

and substation facilities. Own use and losses are represented together as a percent of purchases. An estimate is derived by considering historical percentages and planned improvements to the cooperative's distribution system that would affect the amount of future losses.

Load Forecast Results

The Basin Electric load forecasts are prepared for the three levels of membership. At each level of membership the total energy and demand needed is totaled and is required to be approved by the board of directors of that particular cooperative. Each of the three levels of load forecasts is discussed as follows:

Distribution Cooperative Load Forecasts

The previous forecasting process is employed, with the exception of Tri-State, for each Basin Electric distribution cooperative. The resultant load forecast provides the member with a detailed document outlining the derivations and assumptions utilized in the preparation of its forecast. Member involvement is an integral part of this process as the members provide retail rate projections, judgmental forecasts, and review the econometric models for forecast reasonability and explanatory variable appropriateness. The final product provides each distribution cooperative with a forecast of its annual energy sales by consumer category and monthly forecasts of its wholesale power demand and energy requirements.

G&T Cooperative Load Forecasts

The G&T's Load Forecasts are prepared by adding together the projected purchases of their distribution members. Transmission losses and member diversity within G&T's are also considered where applicable. The G&T Load Forecasts provide a forecast of the total sales of the G&T distribution member categorized according to consumer classifications. It also contains a forecast of the total wholesale power requirements of the G&T. These power requirements are separated into Western and Basin Electric, along with any other power suppliers' components in accordance with the member's contracts with the power supply organizations.

Basin Electric's Load Forecast

Basin Electric's Load Forecast is prepared by adding together the projected power requirements of its 18 Class A Members and the one Class D Member. The resultant forecast reflects the combined power requirements of Basin Electric member cooperatives.

These results are then translated into a model that represents the Basin Electric system on a delivery point basis. This allows the planning of infrastructure improvements to be made where needed, and planning of loads by balancing area to meet resource adequacy needs of the planning areas.

The Load Forecast is then monitored on a monthly basis to ensure that the forecast is performing as expected. Also, due to the detailed information available from the large commercial sector, individual projects can be monitored to ensure that they are proceeding as planned. If the load deviates significantly from the forecast, modifications can be made for future load forecasts.

Summary of the Latest Load Forecast

Basin Electric finalized the 2018 Load Forecast which went to the Basin Electric Board of Directors in January 2018. The load forecast is net of any member's load management activity, which is discussed in more detail later.

Member Forecast

The following graph shows actual total member sales by class such as residential, commercial, etc., from 2000 to 2016 and projected member sales by class from 2017 to 2028. The need for additional generating capacity is driven by the increasing use of electricity and the resulting load growth including industrial growth, energy sector (coal, oil, gas and ethanol bio-diesel) development and new rural development. Between actual 2016 and forecasted 2028, Basin Electric's portion of this load growth is expected to grow more than 6 million MWh in total energy sales which is approximately 579,000 MWh per year. Strong growth in the Williston Basin Oil sector is underpinned by historically strong residential and non-energy related commercial sectors. A view of each sectors growth is below.

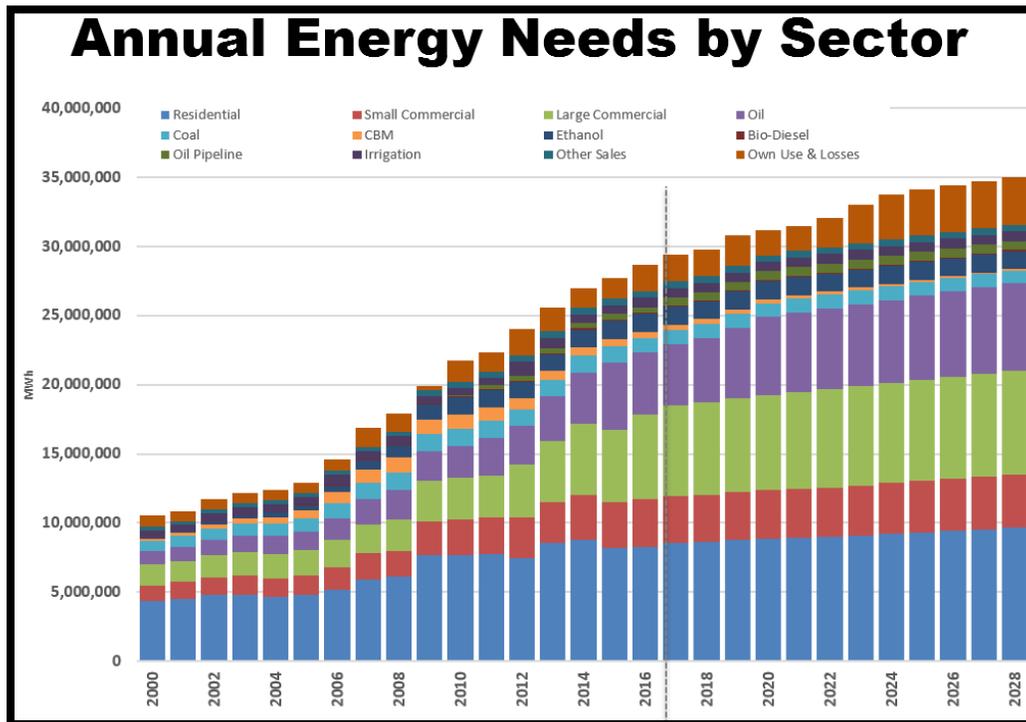


Figure 6-3 Total Member Requirements by Sector

Basin Electric's supplemental power supply responsibility to its member systems is, in most cases, computed by subtracting the members' direct Western allocation from their total power requirements. In instances where other power supply sources are applicable, contractual arrangements are considered.

After other power suppliers obligations are considered, the remainders of the loads are Basin Electric’s responsibility. The following graph depicts the expected Summer Demands for Basin Electric.

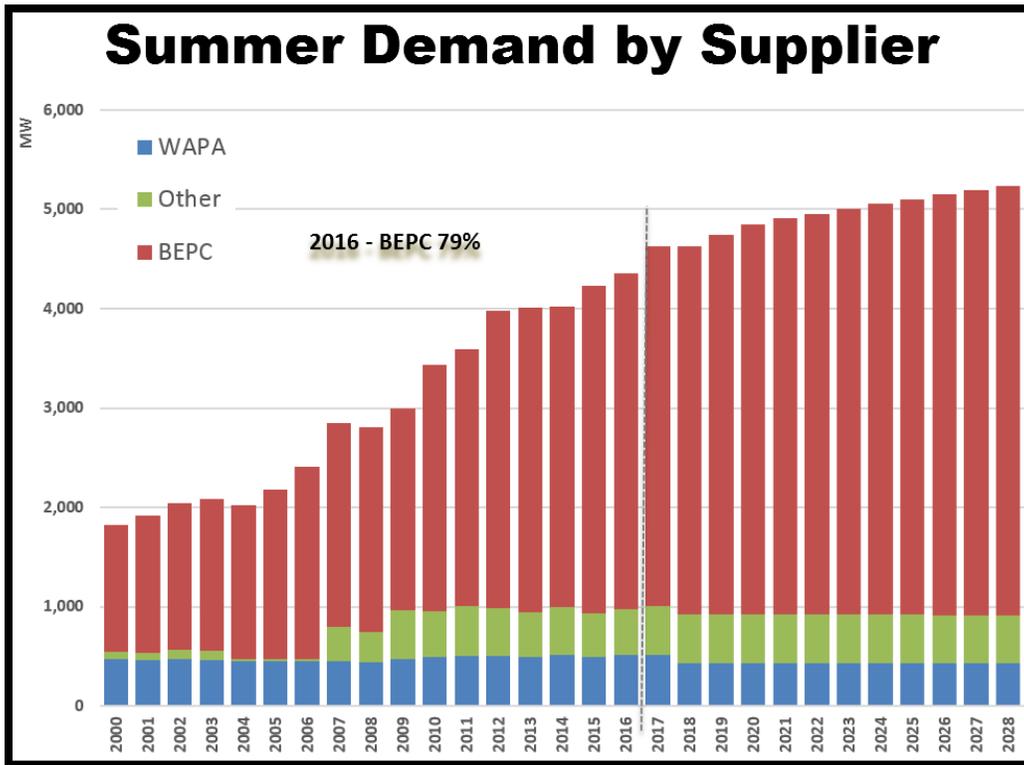


Figure 6-4 Summer Demand by Power Supplier

The following table shows Basin Electric’s member energy sales and member peak demand from 2011 through 2017. System peak demand increased on average by 170 MW annually from 2011 to 2017. System energy sales have been increasing on average by 1,042,143 MWh annually from 2011 to 2017. The total system experienced annual average percent load factors in the high 60’s during this same time period.

| Year | Peak MW | % ACGR | Annual MWh | % ACGR |
|----------------------------|------------------|------------------|----------------------|------------------|
| 2011 | 2,698 | | 16,976,000 | |
| 2012 | 2,994 | 11.0% | 18,556,000 | 9.3% |
| 2013 | 3,340 | 11.6% | 20,162,000 | 8.7% |
| 2014 | 3,559 | 6.6% | 21,558,000 | 6.9% |
| 2015 | 3,600 | 1.2% | 22,379,000 | 3.8% |
| 2016 | 3,682 | 2.3% | 23,333,000 | 4.3% |
| 2017 | 3,885 | 5.5% | 24,271,000 | 4.0% |
| 2011 to 2017 period | 198 MW/yr | 6.3% ACGR | ~1,216 GWh/yr | 6.1% ACGR |

Table 6-1 Historical Member Sales (Billing Load Levels)

Because of the variability of the large oil related, interstate pipeline loads and additional rate pressure concerns, a bandwidth forecast was developed. The high forecast included all cases that would increase loads. The Keystone XL pipeline along with no impacts from higher rates. The low forecast included all impacts that would decrease loads. This case did not include the Keystone XL pipeline and negative effects of rate increases. There were several iterations and combinations of these cases were considered and fall between the high and low cases. The following graphs depict this bandwidths effects on Basin Electric’s loads on a summer demand (Figure 6-5) and annual energy (Figure 6-6) basis

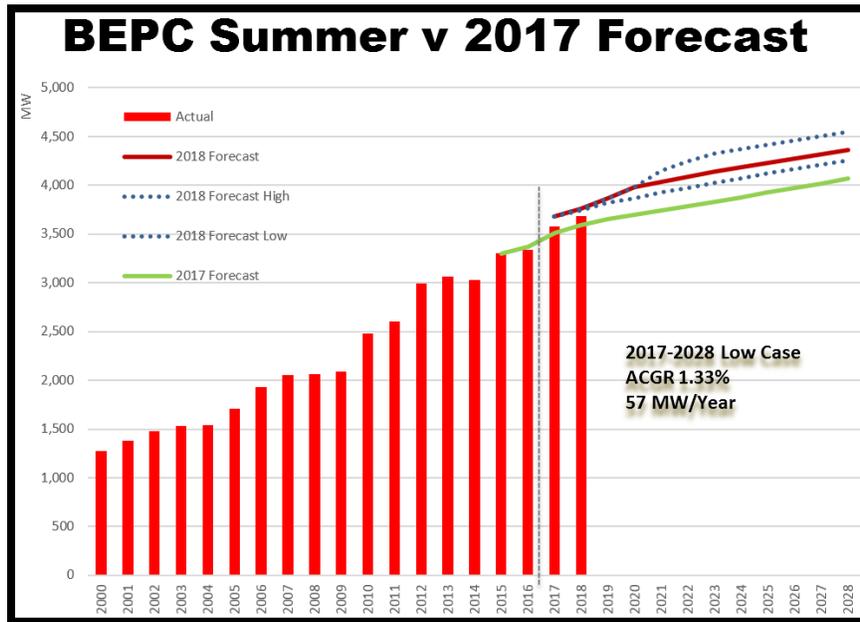


Figure 6-5 Basin Electric Summer Demand

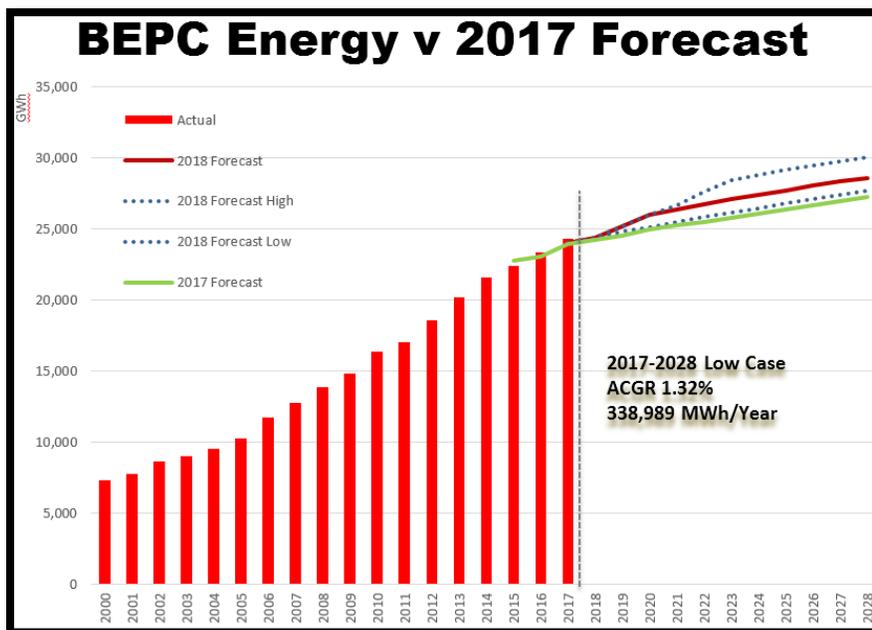


Figure 6-6 Basin Electric Annual Energy Sales

The following graph depicts the performance of the 2018 Load Forecast. Significant growth is expected to continue in the future. Winter 2017/2018 actual peak load was 139 MW or 3.5% above the weather normalized forecast. Summer loads were higher than forecasted, but to a lesser extent, 1.1MW above forecast or about 0.03%.

2018 Load Forecast Performance

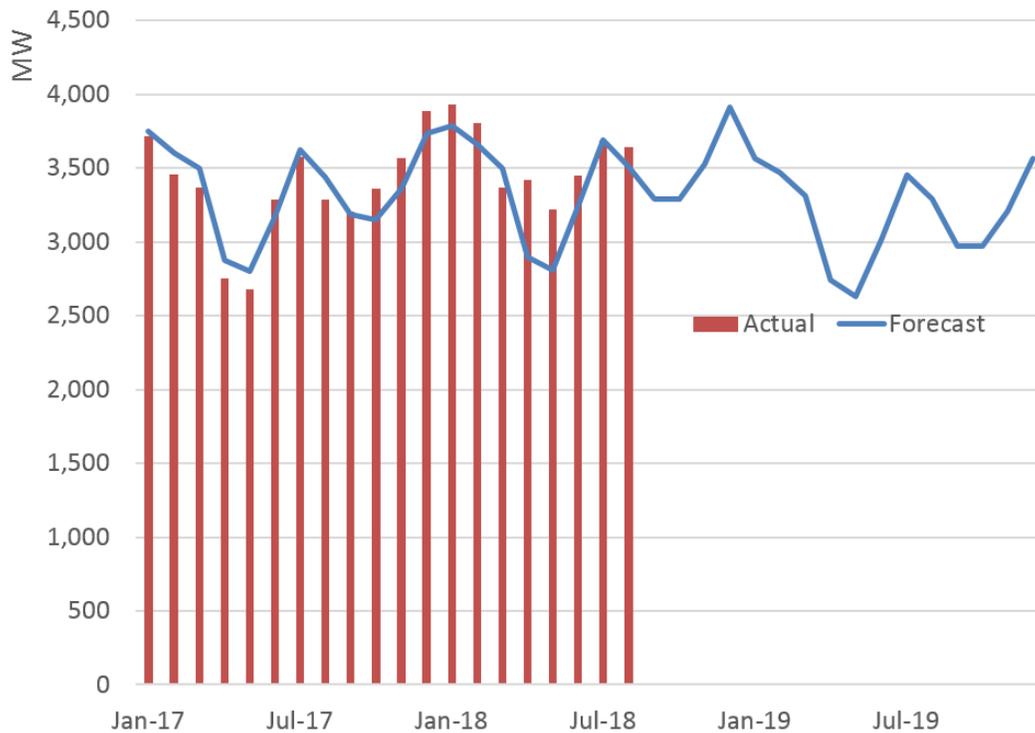


Figure 6-7 Basin Electric Actual v. Forecast

Coincident Peak Load Forecast

Each G&T members load forecasts is developed as its own coincident peak for their planning purposes. These forecasts are then grouped together to represent the loads for Basin Electric’s system by power supply planning region. However, due to each member’s coincident peaks not usually occurring at the same time, the overall regional peak is usually less than that of the sum of the member’s coincident peaks. This historical diversity is tracked, reviewed, and utilized to adjust the member’s coincident peak forecasts appropriately to create a regional coincident peak forecast that is then used for Basin Electric’s power supply planning and modeling purposes.

Originally Basin Electric was utilizing a “low” case forecast that tracks approximately 120 MW lower than what was referred to as the “baseline” case forecast that includes additional loads in one of Basin Electric’s member system that we are not confident will materialize as of yet. The “high” load forecast being used also includes additional loads coming on associated with the Keystone XL pipeline. As the year progressed and Basin Electric has monitored the actual loads compared to the forecast, it was decided that the low case was a little too low, so another case was created in-between the low and high cases that is now being utilized for power supply planning purposes.

Existing Resources

Thermal Plants

1. Leland Olds Station: Leland Olds Unit 1 was placed in-service on January 9, 1966 and is a base-load coal fueled unit located near Stanton, ND, with a net capacity of 222 MW. Leland Olds Unit 2 is a coal fueled unit that was placed in-service on December 15, 1975 and its net capacity is rated at 445 MW. Basin Electric installed sulfur dioxide (SO₂) emission control equipment at the Leland Olds Station which requires an increase to the station service. This equipment was put in service after the 2012 fall outage on Unit 2 reducing the net capacity from 448 MW to 445 MW due to additional station service required. The emissions control equipment was put in service on Unit 1 following the spring 2013 maintenance outage. Additional pollution control equipment to reduce nitrous oxides (NO_x) and mercury emissions was installed for both units. Leland Olds Station Unit 1 is the oldest base-load generating unit in Basin Electric's fleet.
2. Laramie River Station: Basin Electric, together with other owners, began construction of the three coal-fired base-load units at Laramie River Station near Wheatland in southeast Wyoming in July, 1976. LRS has three steam turbine generators supplied by General Electric Company and three steam boilers supplied by Babcock and Wilcox Company. The station's three units became fully operational on November 1, 1982, with Unit 1 at a net capacity of 570 MW; Unit 2 at a net capacity of 570 MW; and Unit 3 at a net capacity of 570 MW. The current rating of the units is due to turbine upgrades that occurred in 2007, 2008 and 2009. Basin Electric is in the process of installing additional emission control equipment at the Laramie River Station. Unit 1 is getting Selective Catalytic Reduction (SCR) equipment and Units 2 and 3 are each getting Selective Noncatalytic Reduction (SNCR) equipment, where the SNCRs are expected to have negligible impact to station service but the SCR is estimated to add around an additional 12 MW. Expected in service dates of the new equipment is in the first half of 2019 for unit 1 and end of year 2018 for units 2 and 3. Basin Electric owns 42.27 percent of the entire project, which results in 723 MW today and approximately 718 MW once the new emission control equipment is installed. Basin Electric, as Project Manager and Operating Agent for the Missouri Basin Power Project, was assigned overall responsibility for the design, construction and operation of the power plant and related transmission. Units 2 and 3 of the Laramie River Station are electrically connected to the western system; Unit 1 is electrically connected to the eastern system. The amount of power Basin Electric receives from the eastern unit currently is 100 MW and the amount of power Basin Electric receives from the western units is 624 MW. Once the new emission control equipment is installed, the amount of power Basin Electric receives from the eastern unit will be approximately 90 MW and the amount of power Basin Electric receives from the western units is approximately 627 MW.

LRS was financed through the RUS for all but 19.8 percent. The 19.8 percent financed elsewhere pertains to pollution control bonds and Tax Benefit Transfers. Tax Benefit Transfers were a financing mechanism allowed by the IRS several years ago where an entity that was unable to use tax credits was able to sell those to an entity who could use the credits against the income taxes to be paid.

3. Antelope Valley Station: Antelope Valley Station (AVS) is a two-unit lignite-fired steam electric generating station located in Mercer County, North Dakota. AVS Unit 1 went into commercial operation on July 1, 1984 and AVS Unit 2 went into commercial operation June 1, 1986. AVS is equipped with two steam turbine generators supplied by Westinghouse Electric Corporation and two steam boilers supplied by Combustion Engineering. The most recent Uniforms Rating of Generating Equipment (URGE) is 450 MW for AVS Unit 1 and 450 MW for AVS Unit 2. Antelope Valley provides approximately 145 to 165 MW of electric power for the neighboring Dakota Gasification Company's Great Plains Synfuels Plant.

Designed to be environmentally sound, over \$394 million has been invested in capital pollution control asset investments for AVS, to date. Dry scrubbers use lime to capture and remove up to 90 percent of sulfur dioxide emissions from stack gases. Fabric filter bag houses capture and remove up to 99 percent of particulate matter. Each bag house contains more than 8,000, 35-foot tall bags. AVS is a “zero-discharge” facility. Even water is used efficiently only leaving the plant site through evaporation. Basin Electric is 100 percent owner of AVS. A portion (45.3%) of AVS Unit 1 was financed through RUS while the other portion (54.7%) was financed through pollution control financing and a loan from CoBank that subsequently replaced a leveraged lease financing. AVS Unit 2 was not financed by the Rural Utilities Service (RUS) but rather by pollution control financing and a leveraged lease. At this time, Basin Electric has elected to not extend the lease and it is scheduled to end December 31, 2020 whereby approximately 340 MW of unit 2 will no longer be available to Basin Electric.



The Antelope Valley Station near Beulah, ND, is one of four coal-based power plants operated by Basin Electric. Its two units began commercial operation in 1984 and 1986.

4. Spirit Mound Station: Basin Electric placed in service a two-unit, 60 MW nameplate No. 2 fuel oil combustion turbines on June 30, 1978 to provide power as a peaking resource. The combined winter rating of the two units is 120 MW and the summer rating is 100 MW. The capacity is intended to be used primarily as reserves or replacement during initial outages of base-load units, during peak load periods when existing base-load units cannot meet the demand or during high market conditions. The site can store in containers up to 8 million gallons of fuel. When the station is in use it consumes 100 gallons of fuel per minute.
5. Earl F. Wisdom Unit 2: Basin Electric partnered with Corn Belt Power Cooperative to build the 80 MW General Electric model 7EA natural gas peaking unit near Spencer, Iowa. Although the combustion turbine uses natural gas as a primary fuel, it can also burn fuel oil as a contingency. Basin Electric owns one half of the unit, which was placed in service in April 2004.
6. Wyoming Distributed Generation: The Wyoming Distributed Generation consists of 9 peaking resource units located at 3 sites; Arvada, Hartzog, and Barber Creek released for commercial operation in 2002.

These units are natural gas fired simple cycle turbines manufactured by Solar and consisting of a total net output of 45 MW summer and 54 MW winter. The turbines are used to hold a portion of the necessary reserves for Basin Electric's west side electrical requirements.

7. Groton Generation Station: The Groton Generation Station near Groton, SD consists of 2 General Electric LMS100 simple cycle gas turbines which provide about 96 MW for Unit 1 and 92 MW for Unit 2 (winter ratings), each as a peaking resource. Basin Electric commissioned Groton Unit 1 in 2006 which was the first commercial application of General Electric's LMS100. Unit 2 began providing power as a peaking resource in 2008. The two gas turbines get their natural gas from the Northern Border Pipeline. Through Dakota Gasification Company's Great Plains Synfuels Plant, the units have firm gas transport which gives them fuel security without requiring a backup or alternative fuel supply. A unique aspect of the station is the ability that Unit 1 has to disconnect the generator from the gas turbine through a synchronous clutch allowing the generator rotor to spin independent from the gas turbine to provide voltage stability to the electrical grid.
8. Culbertson Generation Station: The Culbertson Generation Station, near Culbertson, MT is a single LMS 100 simple cycle gas turbine providing 93 MW (winter rating) of peaking power. Operating since 2010, Culbertson Unit 1 is Basin Electric's first resource located in Montana. Similar to the Groton Generation Station, Culbertson Unit 1 has no need for an alternative fuel source as it receives its fuel from the Northern Border Pipeline and has firm gas transport via the Great Plains Synfuels Plant.
9. Deer Creek Station: The Deer Creek Station combined-cycle natural gas facility is a 300 MW intermediate resource located near Elkton, SD. The station achieved commercial operation in August of 2012. The combined-cycle plant electrical generators are powered by a General Electric model 7FA gas turbine and an Alstom steam turbine. The natural gas fuel used by the station comes from the Northern Border Pipeline where firm gas transport is possible through Dakota Gasification Company's Great Plains Synfuels Plant. The exhaust gases from the gas turbine pass through a heat recovery steam generator where they boil water into steam and provide steam to the Alstom steam turbine. When the combustion turbine has reached full load, duct burners can burn additional fuel within the heat recovery steam generator to produce more steam and reach the full station output ability of 300 MW.



The Deer Creek Station near Brookings, SD, is Basin Electric's first natural gas-fired combined cycle power plant.

10. Dry Fork Station: The Dry Fork Station is a 405 MW coal fired power plant located 10 miles north of Gillette, Wyoming which was released for commercial operation in 2011. Basin Electric owns 92.9% of the station or 376 MW of the base-load resource. The station utilizes Powder River Basin coal from the next door Dry Fork Mine to ensure an uninterrupted, stable priced fuel supply. The latest generation of pollution control technology was implemented resulting in very low emission rate.
11. Pioneer Generation Station: The Pioneer Generation Station is a plant that consists of three GE LM6000 natural gas fired simple cycle combustion turbines and twelve 9.3 MW Wartsila natural gas-based reciprocating internal combustion engines (RICE) located near Williston, North Dakota. The station's Unit 1 became operational in 2013 at a net capacity of 45 MW, Units 2 and 3 became operational in 2014 at a net capacity of 45 MW each, and the twelve internal combustion engines (Units 11 through 22) became operational in 2017. This peaking resource uses natural gas fired simple cycle combustion turbines and reciprocating internal combustion engines fueled by the Northern Border Pipeline. Unit 1 has a clutch located between the combustion turbine and generator allowing the generator rotor to rotate independent of the turbine acting as a synchronous condenser to provide voltage stability to the electrical grid.
12. Lonesome Creek Station: Lonesome Creek Station is a 5 unit natural gas fired power plant located near Watford City, North Dakota. Unit 1 became commercially operational in September of 2013, Units 2 and 3 became commercially operational in January of 2015, and Units 4 and 5 became commercially operational in March of 2017 all five with a net capacity of 45 MW each. This peaking resource uses natural gas-fired combustion turbines fueled by natural gas from the Northern Border Pipeline. Unit 1 has a clutch located between the combustion turbine and the generator allowing the generator rotor to spin independent of the turbine acting as a synchronous condenser providing voltage stability to the electrical grid.

Renewable Resources

1. Chamberlain Wind Project: Basin Electric, in partnership with East River Power Cooperative, has constructed a wind energy project near Chamberlain, South Dakota. The 2.6 megawatt capacity project was placed into commercial service in January 2002. Chamberlain Wind Project is owned by Basin Electric Power Cooperative and the energy is delivered to members as part of Basin Electric's overall power supply.
2. Minot Wind Project: Basin Electric, in partnership with Central Power Electric Cooperative, has constructed a wind energy project 14 miles south of Minot, North Dakota. The 2.6 megawatt capacity wind project was placed into commercial service in February 2002. Three additional turbines were added in December 2009 for a total output of 7.1 megawatts. The facility is owned by Basin Electric.
3. PrairieWinds 1: Basin Electric constructed and owns a wind energy project of 77 turbines near Minot, North Dakota. The 115.5 MW capacity wind project was placed into commercial service in December, 2009.
4. Crow Lake Wind Project: Basin Electric, in partnership with Mitchell Technical Institute (MTI), has constructed a wind energy project of 108 turbines near White Lake, South Dakota. The 162 MW capacity wind project was placed into commercial service in 2011. Basin Electric owns 107 turbines or 160.5 MW. Basin Electric has a purchase power contract for the output from MTI's single turbine or additional 1.5 MW from the Crow Lake Wind Project.



The Crow Lake Wind Project, northwest of Mitchell, SD, was developed in conjunction with Mitchell Technical Institute

Demand Side Management

Demand-side Management (DSM) is the process of managing the consumption of energy, generally to optimize available and planned generation resources. According to the DOE, DSM refers to “actions taken on the customer’s side of the meter to change the amount or timing of energy consumption. Utility DSM programs offer a variety of measures that can reduce energy consumption and consumer energy expenses. Electricity DSM strategies have the goal of maximizing end-use efficiency to avoid or postpone the construction of new generating plants.”

DSM programs aim to achieve three broad objectives; energy conservation, energy efficiency and load management. Energy conservation can reduce the overall consumption of electricity by reducing the need for heating, lighting, cooling, cooking and other functions. Energy efficiency encourages consumers to use energy more efficiently, thus more effectively. Load management allows generation companies to better manage the timing of their consumers’ energy use and will help reduce the large discrepancy between on-peak and off- peak demand.

Basin Electric and its members are engaged in a variety of conservation and energy efficiency programs. The programs and activities were developed to promote, support and market dual heat, water heaters, heat pumps, air conditioning, storage heating, grain drying, irrigation, photovoltaic, energy audits, and numerous other programs . A number of Basin Electric’s members have developed programs. These vary depending on the cooperative; some elect to utilize rebates, others energy resource conservation (ERC) loans, others rates, some all three and some may elect not to adopt any of the programs.

Prior to 2011, Basin Electric had surveyed its membership directly on all DSM activities and reported the information accordingly. Starting in 2011 Basin Electric adopted the new Rural Utilities Service (RUS) and Cooperative Finance Corporation (CFC) energy efficiency information reported by Basin Electric’s members on their RUS’s Form 7 part P or CFC’s Form part S documents.

The dollars spent on DSM program activities by Basin Electric/Members for the last three years are summarized in Table 6-2below.

| DSM Programs | 2017 | 2016 | 2015 |
|----------------------------------|-------------|-------------|-------------|
| Energy Efficiency & Conservation | \$3,865,480 | \$3,939,146 | \$3,505,806 |
| Load Management | \$2,535,795 | \$2,476,914 | \$2,188,749 |
| Total DSM Programs | \$6,401,275 | \$6,416,060 | \$5,694,555 |

Table 6-2 Annual Dollars Spent on DSM Programs

Energy conservation and efficiency programs are capable of lessening the impact of electrical demand and reducing the capacity needs of additional future generation facilities. Energy conservation is behavior based while energy efficiency is technology based. Therefore, energy conservation and efficiency programs could be considered in parallel of adding additional generating capability to meet the Basin Electric projected demand.

The Demand (kW) Savings associated with DSM program activities by Basin Electric/Members for the last three years are summarized in Table 6-3 below.

| Demand (kW) Savings | 2017 | 2016 | 2015 |
|----------------------------------|---------|---------|---------|
| Energy Efficiency & Conservation | 85,910 | 32,482 | 6,507 |
| Load Management | 164,164 | 179,574 | 208,434 |
| Total DSM Programs | 250,074 | 212,056 | 214,941 |

Table 6-3 Annual kW Savings on DSM Programs

Energy conservation and efficiency programs are capable of lessening the impact of electrical energy needs therefore reducing additional future generation facilities. Energy conservation is behavior based while energy efficiency is technology based. Energy conservation and efficiency programs could be considered in parallel of adding additional generating capability to meet the Basin Electric projected energy obligations.

The Energy (kWh) Savings associated with DSM program activities by Basin Electric/Members for the last three years are summarized in Table 6-4 below.

| Energy (kWh) Savings | 2017 | 2016 | 2015 |
|----------------------------------|-------------|-------------|------------|
| Energy Efficiency & Conservation | 526,801,660 | 199,177,249 | 39,898,098 |
| Load Management | 42,991,499 | 56,858,270 | 50,336,056 |
| Total DSM Programs | 569,793,159 | 256,035,519 | 90,234,154 |

Table 6-4 Annual kWh Savings on DSM Programs

The Energy Efficiency & Conservation information can include a combination of but not limited to the following DSM activities:

Agriculture/Irrigation

- Appliance rebate programs
- Audit and building envelope measures Cooling/ventilation measures
- Heating/drying measures
- Load management programs
- Pump/motor/ASD measures
- Refrigerator/freezer measures

Commercial/Industrial

- Air conditioning measures
- Appliance rebate programs
- Audit and building envelope measures
- Cooking measures
- Heating measures
- Hot water measures
- Motor/ASD programs
- Refrigerator/freezer measures
- Ventilation measures

Commercial/Industrial/Agriculture/Irrigation

- Lighting measures
- Load management programs
- Industrial process measures

Residential

- Air conditioning measures
- Appliance rebate programs
- Audit and building envelope
- Cooking measures
- Domestic hot water measures
- Heating measures
- Lighting measures

Load management programs
Refrigerator/freezer measures
Ventilation measures
Other



Basin Electric provides specialized equipment to member cooperatives for use in energy audits.

It is the objective of our members to work for and support programs to promote the conservation of electrical energy that includes the widespread understanding, participation and involvement of the member-consumers of the cooperative. Some of their objectives are to:

- Constantly examine their use of energy. This includes, but is not limited to, plant engineering design and construction, lighting and climate control.
- Direct effort toward conservation of energy by discouraging wasteful and unnecessary uses of energy.
- Encourage improved efficiency in energy-consuming devices.
- Encourage the effective and efficient use of energy in the home, on the farm, and in business uses that includes energy conservation, adequate home insulation and weatherization.
- Develop and carry out information programs that will encourage energy conservation through proper thermostat settings for heating and cooling devices.
- Develop training as appropriate for all employees and others interested in such training.

Basin Electric and its members are engaged in a variety of conservation and energy efficiency programs. The programs and activities were developed to promote, support and market dual heat, water heaters, heat

pumps, air conditioning, storage heating, grain drying, irrigation, photovoltaic, energy audits, and numerous other programs .

Electric Heat Programs

The membership promotes the utilization of electric heat in consideration of its efficiency, convenience, safety, cleanliness, quietness, reliability and versatility. The programs for electric heat include four categories consisting of heat pumps, storage heating, dual heating and conventional electric heat.

Electric Heat Pump Programs

The heat pump programs consist of both ground source and air-to-air systems. Ground source heat pumps do not utilize a heating element. They operate by extracting heat from the ground, which has a temperature of 40 to 50 degrees, and delivering it to the home at 90 to 125 degrees. The heat exchange with the ground occurs via a series of plastic pipes that are placed in either vertical or horizontal positions. This process results in efficiencies between 300 and 400 percent. A reversible valve enables the heat pump to remove heat from inside the home in the summertime and return it to the ground. Ground source heat pumps are normally connected to the consumer's hot water heater, which also provides for very economical water heating costs.

Air-to-air heat pumps operate on the same principal as ground source heat pumps. The only difference is the heat exchange occurs with the air and results in efficiencies of 200 to 300 percent.

Electric Storage Heat Systems

The electric storage heat systems are normally constructed of high-density bricks. This enables the bricks to be electrically charged with heat during the off-peak low load periods and the heat is then discharged from the bricks into the home during the high load on-peak periods rather than using electricity to generate the heat. This operation, which transfers on-peak electrical usage to off-peak periods, is incorporated as part of the members' demand-side management (DSM) systems.

Conventional Electric Heat

As heat pumps and storage heaters continue to gain acceptance, the percent of electrically heated homes utilizing conventional electric resistance heat has decreased.

Dual Heating Systems

Dual heating systems are also installed as part of the members' DSM programs. These systems allow the consumer to heat their residence with electric heat or a fossil fuel such as propane or fuel oil. DSM systems may be used to remotely turn off the electric heat and start the backup fossil fuel furnaces to reduce on-peak electric usage. This reduces the on-peak amount of electric power while still meeting the consumer needs for heat.

The members utilize the dual fuel concept as a marketing tool that enables them to market additional power without increasing their purchase power costs during peak periods. Dual heat systems have typically resulted in electric heat being added to homes with fossil fuel furnaces. There are, however, many cases where fossil fuel furnaces have been added to all electric homes, which demonstrate the members' commitment to this program.

Figure 6-8 categorizes Basin Electric Members' electric heating systems installed by type.

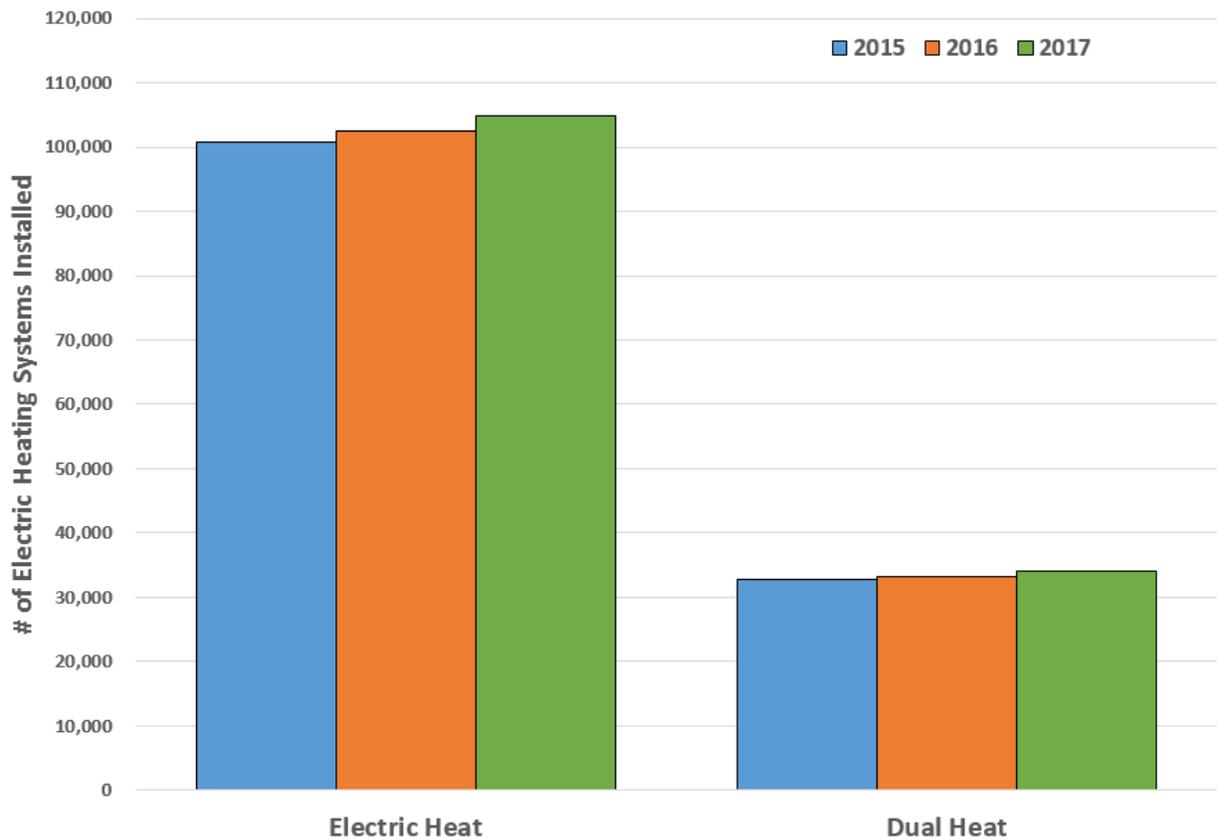


Figure 6-8 Electric Heating Systems Installed by Type

Member Load Management Program

Approximately half of the members are utilizing load management to manage their power purchases from Basin Electric. Other members have investigated load management, but the high load factor of their Commercial loads and the system cost results in marginal economics. Some of Basin Electric's members have provided hourly estimated data regarding their Load Management Systems. Those members include:

- Central Power Electric Cooperative
- East River Electric Power Cooperative
- L and O Power Cooperative
- Northwest Iowa Power Cooperative
- Rushmore Electric Power Cooperative

Figure 6-9 shows the amount of load management by month for the Basin Electric members that have provided data, based on year 2017 strategy. The graph shows the maximum load management that occurred within those member systems with load management in any one hour for each month in 2017, as well as, a comparison to the strategy that was in place going into the year for Central Power, East River, L&O, NIPCO, and Rushmore. The other members are not monitored within Basin Electric to determine actual amounts of load management that occurred. This magnitude of load management is factored into the load forecast for each member with load management.

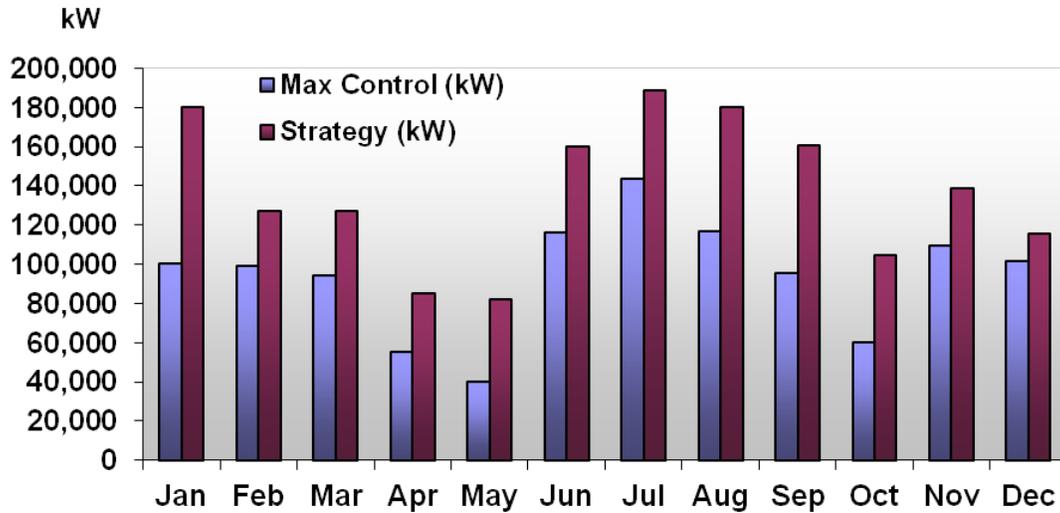


Figure 6-9 Maximum Load Management for Basin Electric Members (Total)

Figure 6-10 shows the total amount of load management that the member systems with load management had on their systems each month for 2017.

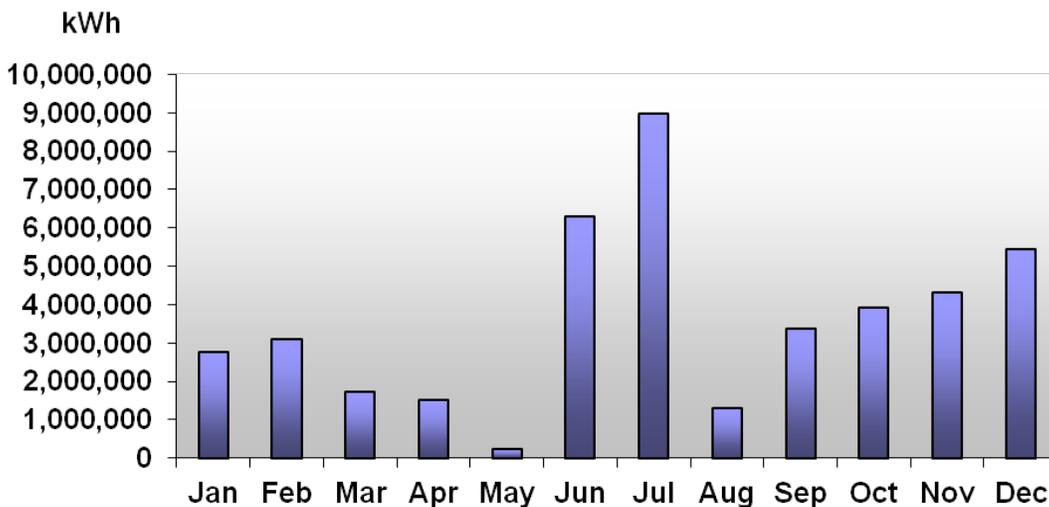


Figure 6-10 2017 Total Load Management (kWh)

Figure 6-11 shows that actual percent of utilization that occurred by month for load management for 2017.

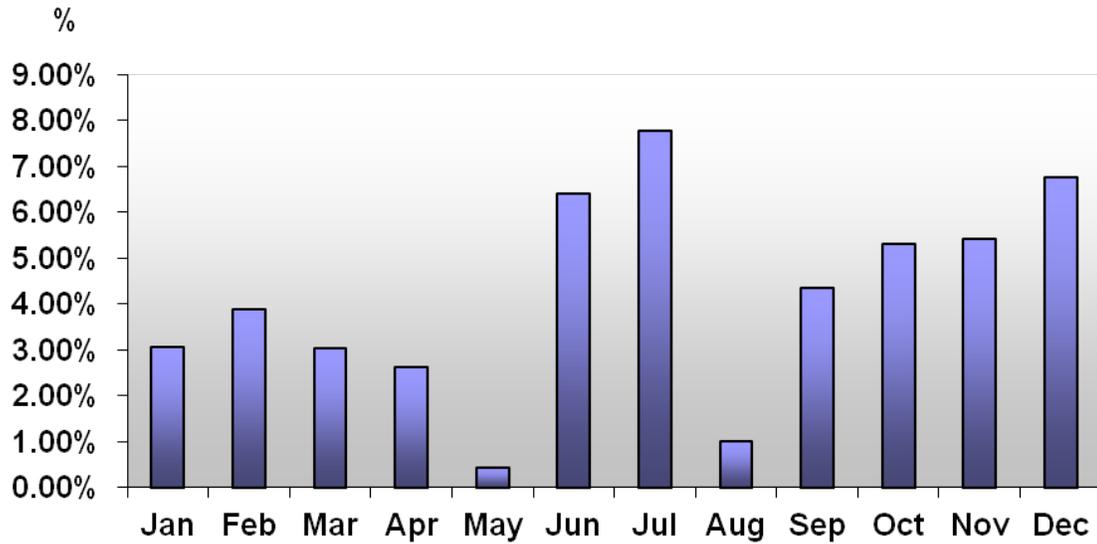


Figure 6-11 Load Management System Percent of Utilization

Figure 6-12 shows a comparison of the load factors with and without the load management factored in. As can be seen in Figure 6-12, implementing load management increases the load factor on the system.

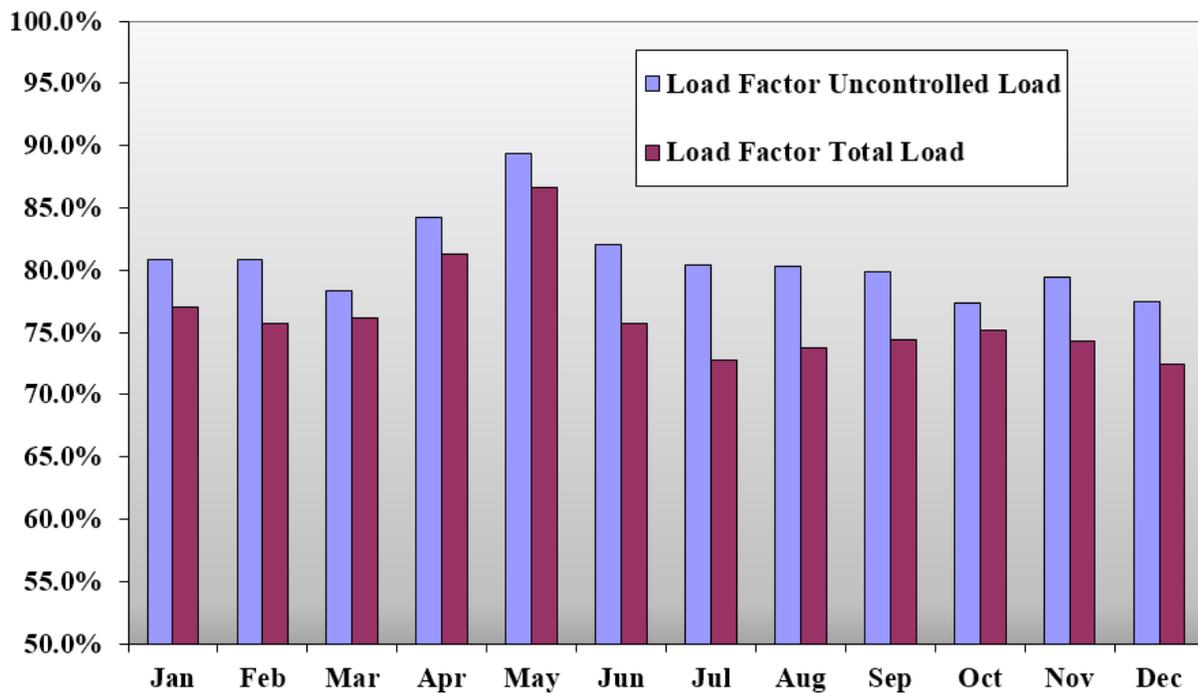


Figure 6-12 Load Factor With and Without Load Management

Figure 6-13 shows the number of days the member systems with load management systems had load management. There were a total of 271 days with load management.

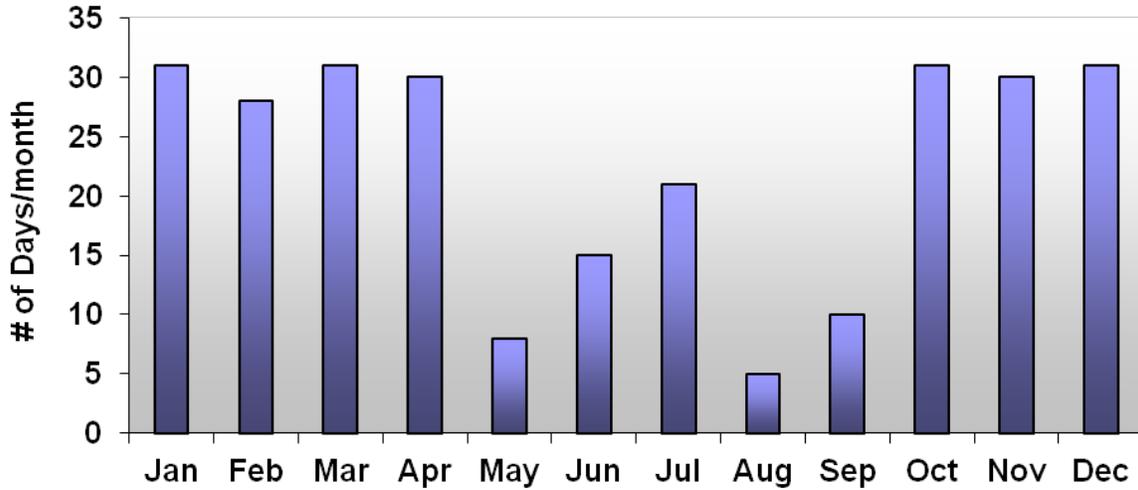


Figure 6-13 Total Days of Load Management

Figure 6-14 shows the average number of hours per day load management operated when there was load management operating. There were a total of 4,143 hours of load management during 2017.

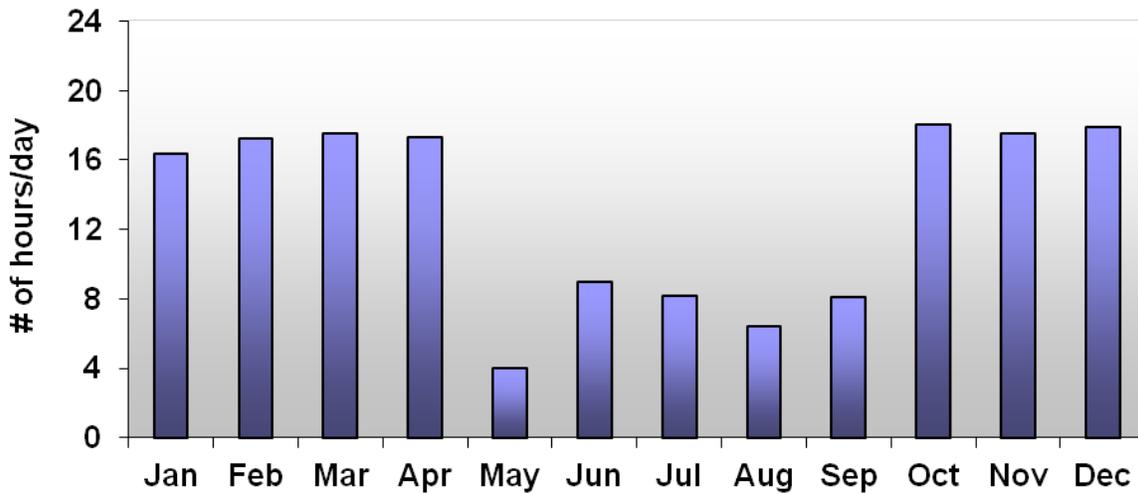


Figure 6-14 Average Daily Hours of Load Management

Details about individual members' load management systems were provided by each member.

Central Power Load Management

Central Power Electric Cooperative (Central Power) operates a 17-level, ladder control system; i.e. control levels, numbered from zero to sixteen, with zero exercising no control and 16 exercising maximum control.

Control is activated at predetermined demand thresholds and deactivated at much lower predetermined thresholds to accommodate demand rebound. In order for a device that is being controlled to be released from control, all of the devices assigned to higher numbered control levels must first be released from control (i.e. level 16 must be released before 15 can be released, and so on).

| | | | | | | | | |
|---------------|---------------------------|------------|--|--|------------|--|----------|------------|
| Device | Irrigation and Coal Creek | Grain Heat | Large Water Heaters 25% off 75% on | Small Water Heaters 25% off 75% on | Irrigation | Large Water Heaters 50% off 50% on | Non-Heat | Grain Heat |
| Control Level | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |

| | | | | | | | | |
|---------------|-----|--|--|--|----------|--|------------|--|
| Device | A/C | Large Water Heaters 75% off 25% on | Large Water Heaters 75% off 25% on | Small Water Heaters 50% off 50% on | Generate | Small Water Heaters 75% off 25% on | Grain Fans | Generate, Small Water Heaters 75% off 25% on |
| Control Level | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |

Table 6-5 Central Power Load Management Levels (Summer)

Level 1 control initiated based on total load including commercial pumping.

Level 11 no time limit.

Level 16 has a two-hour time limit with two hours of recovery time before re-entry.

East River Load Management

Load management refers to the control of various customer electric loads during times of peak usage on the electric system. By managing loads so that they are not all on at the same time, the cooperative is able to reduce wholesale power purchases, thus saving money and resources.

East River member cooperatives' load management system has been operating for over 30 years and has saved over \$200 million in avoided wholesale power costs. Almost 76,000 different electric loads in homes, farms and businesses of member consumers throughout Eastern South Dakota and Western Minnesota with a total 500 MW are connected to the system. These loads include electric water heaters, air conditioners, irrigation systems and large industrial processes.

Control is initiated monthly through a highly sophisticated system that communicates with control receivers connected to the various loads. East River operates the system on a federated basis on behalf of its member systems to moderate wholesale power costs, improve system efficiencies and provide member consumers with energy options.

Make-up/Magnitude:

Table 6-6 shows the make-up and magnitude of load management on East River's system.

| | A/C | Central Heat Storage Furnaces | Residential Demand Limiters | Water Heaters | Irrigation | Industrial and Grain Dryers | Diesel Generators |
|--------------|--------|-------------------------------|-----------------------------|---------------|------------|-----------------------------|-------------------|
| Loads | 22,100 | 1303 | 36 | 49,700 | 1,900 | 4,000 | 97 |
| MW | 82 | 4 | 1 | 215 | 102 | 60 | 36 |

Table 6-6 East River Load Management Make-up/Magnitude

Operation:

Operated on a monthly basis, each control is initiated by East River dispatch. Using Supervisory Control and Data Acquisition (SCADA) to monitor the East River system load, East River dispatchers initiate low frequency power line carrier signals to over 60,000 load control receivers installed at consumer loads. Participation by consumers is voluntary.

Jointly defined and reviewed annually by East River and their members systems, the operating strategy limits the amount of the time water heaters, air conditioners, and central storage units are controlled during each control period. The goal is to have 100 percent of all applicable controllable load groups for each month controlled during the East River monthly peak.

The East River load curve, our controllable/non-controllable load ratio, and the voluntary participation of our consumers require a portion of the controllable water heating load and air conditioning load to be on during the monthly peak.

Summary of Studies Concerning Potential Expansion:

Under current programs, we are connecting approximately 1 MW of additional controllable water heater load and approximately 1 MW of additional controllable air conditioning load to our system each year. Currently we do not directly limit additional controllable load.

Much attention has been given to the existing load management system, the amount of load connected to it, how it operates, and the impact on their consumers. In addition to new controllable loads, there is non-controllable load growth as well. This has resulted in a relatively stable controllable/non-controllable load ratio.

L&O Load Management

The current L&O Power Cooperative (L&O) load management system consists of a power line carrier Cannon Yukon system.

L&O currently operates the system to attempt to have all available load to be controlled "off" over their monthly peak, each month. The loads controlled change from month to month (season, interruptible 5/7, etc.) but the operational goal each month is to have all available controllable load off over the time of the L&O monthly peak.

L&O feels that its current ratio of controlled load to total load is probably as high as it wants to go at this time. Its Load Management penetration is fairly high and the control times each month are as high as or higher than its customers would like to see, resulting in some cold water complaints in extreme weather months. Note that this is based upon historical data and L&O’s current load management system operations. The current switches operated by the L&O load management system are estimated as follows:

| A/C | Heat Pump (Summer) | Dual Fuel | Water Heaters | Irrigation | Grain Dryers | Interruptible (5/7) |
|------------|-------------------------------|------------------|--------------------------|-------------------|-------------------------|--------------------------------|
| 82 | 122 | 520 | 3200 | 18 | 20 | 0 |

Table 6-7 L&O Load Management Estimated Switch Installations

Northwest Iowa Power Cooperative (NIPCO)

One of NIPCO’s most successful programs is the “Switch Makes Cents” program. It was launched in 1983 to encourage the wise use of electricity. The objective of the program is to increase the cost-effective use of energy efficient equipment applications while maximizing the power supply resources and transmission system. The NIPCO Members make available to the member-consumers incentives, equipment rebates and rate savings offered for the installation of new energy efficient equipment. Special electric rates are made available in exchange for allowing this equipment to be interrupted during system peak use through the demand-side component of the Switch Makes Cents program.

To date, nearly 17,583 demand-side management switches have been installed in members’ homes and businesses. This 35 year old energy and demand efficiency program has resulted in member savings of more than \$43.5 million. The demand side management component of the program saved the member consumers over \$3.6 million in 2016 alone.

Rushmore Electric Power Cooperative

Rushmore Electric Power Cooperative (REPC) uses load management to shift load during system peak periods to lower peak demands and minimize the electrical stress on the system. This is done by turning off high usage electrical equipment during peak hours through an automated system. Currently we control water heaters, central AC units, irrigation, water systems, and storage heat.

REPC’s load management program is still in its infancy stage, only being in operation since early 2017. Typical monthly control ranges from 1-8 days with most control windows lasting 1-4 hours. Currently there are 7,657 different electrical loads under control. This resulted in a reduction of 19.5 MW in June 2017. To date, REPC members have saved a total of \$6,446,564 through load management.

The load management system is made up of several components which are seamlessly integrated. It starts with the ACS SCADA system monitoring each of REPC’s delivery points. The kW load is summed, giving the total load on Rushmore’s system. This load data is sent to the load control program to be used as a trigger for load control.

The load control program was designed in house and is the brains behind when load control is started and stopped. There are predefined control windows set within the program, one for morning control and one for afternoon/evening control. The program monitors the system load that it receives from the SCADA system. When the system load is above a preset limit and within one of the two control windows, a signal is sent out to the member cooperatives TWACS servers to turn load off. When the system load is below a preset level, a signal is sent to the TWACS servers to turn load back on. The TWACS serves process the signal and tell the corresponding DRU (Demand Response Unit) located on the consumer end to turn load on/off.

The control program has many other features that help with the automation process. This has allowed REPC to minimize the overhead costs of having an employee monitor the system 24/7.

In 2017 REPC had \$92,097 in operating and capital expenditures.

Future Expansion

The program is voluntary with each member cooperative providing different incentives to entice consumers to sign up. Within four years, it is Rushmore’s goal to have a total of 15,000 water heaters and 2,000 central AC units under control. Storage heat, irrigation and other larger motor loads will be perused as well.

The load control program will also change as time goes on. As the amount of load under control grows, the philosophy on how it is controlled will have to change and adapt.

Basin Electric Load Management Program

Basin Electric has implemented an east side system-wide load management program that enables Basin Electric to target large loads and/or generation that are not included in the members’ load management programs to be used during Basin Electric’s seasonal peak periods . Basin Electric has approximately 8 MW of load management available at this time.

Figure 6-15 below is the total amount of load management in place in 2017 that Basin Electric used to control their seasonal peak.

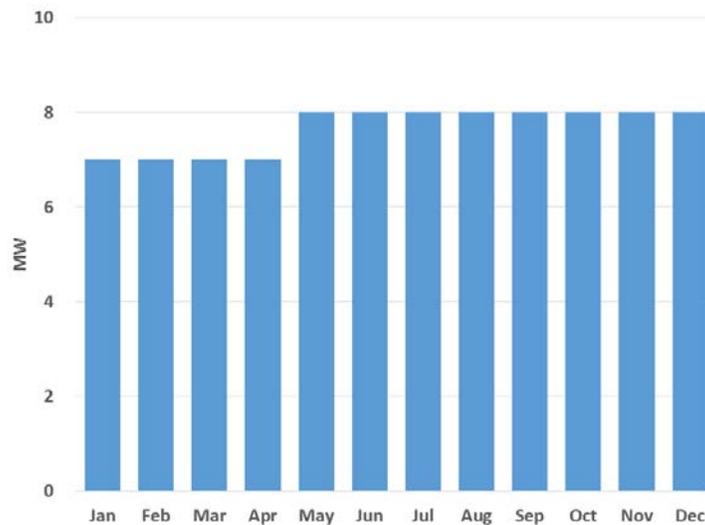


Figure 6-15 2017 Load Management Strategy in Place by Month

Basin Electric will continue to work on developing and expanding on energy conservation and efficiency within the Basin Electric service territory. Basin Electric has always empowered the membership to have the majority of the load management programs at the membership level to allow members to manage their peak and avoid Basin Electric's demand rate. Basin Electric will also work with the members to develop more load management within the Basin Electric system where it is viable.

Power Purchase Contracts

1. Earl F. Wisdom Unit 1: Earl F. Wisdom Generating Station Unit 1 is a 38 MW coal based unit located near Spencer, IA. Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 38 MW of uncommitted capacity and associated energy from the Earl F. Wisdom Unit 1. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. Back in 2015, Wisdom Unit 1 was forced to stop burning coal in accordance with the Utility Mercury and Air Toxics Standards and was retrofitted to allow for natural gas to be the fuel source instead.
2. Earl F. Wisdom Unit 2: Basin Electric partnered with Corn Belt Power Cooperative to build the 80 MW General Electric model 7EA natural gas peaking unit near Spencer, Iowa. Although the combustion turbine uses natural gas as a primary fuel, it can also burn fuel oil as a contingency. Basin Electric owns one half of the unit, which was placed in service in April 2004. Basin Electric purchases 87.5 % of Corn Belt's owned half in response to Corn Belt entering into a Wholesale Power Contract. Therefore Basin Electric has 93.75% or 75 MW from the 80 MW of the combustion turbine.
3. George Neal Station Unit 4: Unit 4 is a 644 MW coal-fired electric generation facility located south of Sioux City, Iowa that has been providing base-load power since 1979. Basin Electric and Northwest Iowa Power Cooperative (NIPCO), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that NIPCO will sell to Basin Electric NIPCO's 31 MW of uncommitted capacity and associated energy from Unit 4 of the George Neal Generating Station. In return NIPCO entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to NIPCO all of NIPCO's capacity and energy requirements in excess of the power and energy available to NIPCO from the Western Area Power Administration .

Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 73 MW of uncommitted capacity and associated energy from Unit 4 of the George Neal Station. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. Unit 4 is connected to MidAmerican Energy Company (MEC) where NIPCO and Corn Belt have rights to bring this energy to the Southwest Power Pool (SPP) or Midwest Independent System Operator (MISO) via MEC. As part of Basin Electric's current Action Plan, Basin Electric plans to have this capacity remain registered in MISO until Summer of 2021, after which it will be brought back in to SPP.

4. Walter Scott 3 and 4: The Walter Scott Energy Center located near Council Bluffs, IA provides base-load power through the 690 MW Unit 3 and the 790 MW Unit 4. While both of the units are coal-based, Unit 3 has been operating since 1979 and Unit 4 began operation in 2007.

Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 26 MW of uncommitted capacity and associated energy from Unit 3 and 45 MW of uncommitted capacity and associated energy from Unit 4 of the Walter Scott Energy Center. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. Walter Scott 3 and 4 are connected to MidAmerican Energy Company (MEC) where Corn Belt has rights to bring this energy into SPP or MISO via MEC.

5. Duane Arnold Energy Center: The Duane Arnold Energy Center consists of a 615 MW nuclear powered unit located near Cedar Rapids, IA, that has been providing base-load power since 1975. Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated with a power supply contract. The contract provides that Basin Electric will purchase Corn Belt's 10% share, which is about 62 MW of uncommitted capacity and associated energy from the Duane Arnold Energy Center. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration. Interconnected to the Alliant West (ALTW) system, Corn Belt has the rights to bring this energy into SPP or MISO via ALTW. Currently this resource is registered in the MISO market.

In July of 2018, NextEra Energy, the operating owner of the Duane Arnold Energy Center (DAEC), Palo, Iowa, announced that commercial operations at the plant will cease in 2020 subject to final approval by the Iowa Utility Board on the termination of an agreement between NextEra and Alliant. With an immediate focus to minimize any financial impact that early closure may have, Basin Electric and Corn Belt Power plan to modify their internal accounting procedures to reflect the change in the plant closure date.

6. Western Area Power Administration Peaking Capacity: In 1968 Basin Electric executed a long-term contract with the federal government for USBR (now Western) hydro peaking from the dams in the Missouri River Basin. This contract currently provides Basin Electric with 268 MW of winter peaking capacity at load and for Basin Electric to return a like amount of energy to Western during off-peak periods. This contract currently goes through December 2020 and is being evaluated for extension from 2021-2050.
7. Western Native American Purchase: Basin Electric receives a Native American Allocation of 39.7 MW in the winter and 40.8 MW in the summer season. This allocation is a result of congressional action that made federal power available to the Native Americans.
8. Madison Diesel: Basin Electric purchases capacity and energy output (when scheduled) from diesel generators owned by the City of Madison, South Dakota. The purchase is for five, 2 MW Caterpillar diesel generators that went commercial in April 2005. The agreement goes through December 2025.
9. Northern Border Waste Heat: Basin Electric purchases the energy from eight Recovered Energy Generation (REG) power plants fueled by hot exhaust off the Northern Border Pipeline compression stations with three units in North Dakota, three units in South Dakota, and one in both Montana and Minnesota for a total generating capacity of 44 MW; 22 MW went commercial in 2006, 22 MW went

commercial by the end of 2009. The generation is environmentally benign, using virtually no additional fuel and producing virtually zero emissions. Basin Electric has signed a 25-year contract with the developer for the output of the REGs.

10. NextEra Wind: Basin Electric purchases all of the energy from six wind projects owned and operated by NextEra. The wind projects include:
 - a. Edgeley Wind Project: 40 MW wind facility near Edgeley, North Dakota. Wind Facility went commercial in 2003. Basin Electric has entered into a 25 year PPA for the power from this facility.
 - b. Hyde County Wind Project: 40 MW wind facility near Highmore, South Dakota. Wind Facility went commercial in 2003. Basin Electric has entered into a 25 year PPA for the power from this facility.
 - c. Wilton 1 Wind Projects: 49.5 MW wind facility near Wilton, North Dakota. The Wilton 1 Wind Project went commercial in early 2006. Basin Electric has entered into a 25-year PPA for the power from this facility.
 - d. Wilton 2 Wind Projects: 49.5 MW wind facility near Wilton, North Dakota. Wilton 2 Wind Project went commercial November 2009. Basin Electric has entered into a 25-year PPA for the power from this facility.
 - e. Day County Wind Project: 99 MW wind facility near Groton, South Dakota. Wind Facility went commercial in 2010. Basin Electric has entered into a 30 year PPA for the power from this facility.
 - f. Baldwin Wind Project: 100 MW wind facility near Baldwin, North Dakota. Wind Facility went commercial in 2011. Basin Electric has entered into a 30 year PPA for the power from this facility.
 - g. Brady 1 Wind Project: 150 MW wind facility near New England, North Dakota. Wind Facility went commercial in 2016. Basin Electric has entered into a 30 year PPA for the power from this facility.
 - h. Brady 2 Wind Project: 150 MW wind facility near New England, North Dakota. Wind Facility went commercial in 2016. Basin Electric has entered into a 30 year PPA for the power from this facility.
 - i. Burke Wind Project (Under Construction): 200 MW wind facility near Columbus, North Dakota. Wind Facility is expected to go commercial in 2019. Basin Electric has entered into a 30 year PPA for the power from this facility.
11. Other Wind Purchases:
 - a. Campbell County Wind Project: 94 MW wind facility near Pollock, South Dakota owned and operated by Consolidated Edison, Inc. Wind Facility went commercial in 2015. Basin Electric has entered into a 30 year PPA for the power from this facility.
 - b. Sunflower Wind Project: 104 MW wind facility near Hebron, North Dakota owned and operated by Novatus Energy. Wind Facility went commercial in 2016. Basin Electric has entered into a 25 year PPA for the power from this facility.
 - c. Lindahl Wind Project: 150 MW wind facility near Tioga, North Dakota owned and operated by Tradewind Energy. Wind facility went commercial in 2017. Basin Electric has entered into a 25 year PPA for the power from this facility.
 - d. Prevailing Winds Wind Project (Under Construction): 200 MW wind facility near Avon, South Dakota owned and operated by sPower. Wind facility is expected to go commercial in 2019. Basin Electric has entered into a 30 year PPA for the power from this facility.

12. PRECorp Allocation: The PRECorp Allocation is a power allocation from the Western Area Power Administration – Rocky Mountain Region (RMR). The RMR allocation provides for fixed monthly capacity and energy deliveries that correspond to the monthly resource capability of the Federal hydro systems. The PRECorp Allocation uses 24 MW in the winter season and 21 MW in the summer season for planning purposes. Basin Electric uses these allocations to the extent possible, as peaking resources due to the limited amount of energy that can be scheduled to maximize the value of these allocations. Effective October 1, 2014 the seasonal energy and CROD for future winter and summer seasons may be reduced by up to 1 percent from the then current seasonal energy and CROD.
13. Webster City CT: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase the output of the Webster City CT peaking plant (20.8 MW summer accreditation) that is fueled by fuel oil. The purchase began September 1, 2009 and continues through the term of the Wholesale Power Contract between Basin Electric and Corn Belt.
14. Estherville Diesel Generators: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase the output from the City of Estherville's six diesel generators (12 MW). The purchase began September 1, 2009 and will remain in effect so long as Corn Belt continues to purchase the output of the diesel generators pursuant to the Wholesale Agreement between Iowa Lakes Electric Cooperative and the City of Estherville, provided that this will not extend through the term of the Wholesale Power Contract between Basin Electric and Corn Belt.
15. Spencer Combustion Turbine (CT) Generator: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase 10 MW from the City of Spencer 20 MW combustion turbine. The purchase began September 1, 2009 and will remain in effect so long as Corn Belt continues to purchase the output of the combustion turbine pursuant to Corn Belt being a party to the Spencer Power Purchase Agreement with Spencer Municipal Utilities of the City of Spencer, Iowa, provided that this will not extend through the term of the Wholesale Power Contract between Basin Electric and Corn Belt.
16. Corn Belt Wind: Basin Electric has signed a contract with Corn Belt Power Cooperative, a member of Basin Electric, to purchase the output of Corn Belt's wind projects. The purchase begins September 1, 2009 and continues through the term of the Wholesale Power Contract between Basin Electric and Corn Belt. The wind projects include: 7.3 MW from the Hancock County Wind Project; 16.8 MW from the Crosswind Generators; 10.5 MW from the Lakota Wind Project; and 10.5 MW from the Superior Wind Project.

17. Bilateral Contracts with Neighboring Utilities: Basin Electric has a number of bilateral PPAs with utilities in SPP, NWPP, and MISO Zone 1. Below in Table 6-8 and Table 6-9 are the summer and winter seasonal capacity totals by region for these shorter term bilateral agreements that were in place as of January 1, 2018.

| | <u>S19</u> | <u>S20</u> | <u>S21</u> | <u>S22</u> | <u>S23</u> | <u>S24</u> | <u>S25</u> | <u>S26</u> | <u>S27</u> | <u>S28</u> |
|-------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| SPP Total | 201 | 201 | 150 | 150 | 150 | 0 | 0 | 0 | 0 | 0 |
| NWPP Total | 100 | 100 | 100 | 75 | 75 | 75 | 75 | 0 | 0 | 0 |
| MISO Zone 1 Total | 325 | 300 | 350 | 325 | 200 | 200 | 0 | 0 | 0 | 0 |
| Overall Total | 626 | 601 | 600 | 550 | 425 | 275 | 75 | | | |

Table 6-8 Bilateral agreements with neighboring utilities - Summer season capacity totals by region

| | <u>W18/ 19</u> | <u>W19/ 20</u> | <u>W20/ 21</u> | <u>W21/ 22</u> | <u>W22/ 23</u> | <u>W23/ 24</u> | <u>W24/ 25</u> | <u>W25/ 26</u> | <u>W26/ 27</u> | <u>W27/ 28</u> |
|-------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|
| SPP Total | 201 | 201 | 201 | 150 | 150 | 0 | 0 | 0 | 0 | 0 |
| NWPP Total | 100 | 100 | 100 | 75 | 75 | 75 | 75 | 0 | 0 | 0 |
| MISO Zone 1 Total | 300 | 325 | 300 | 350 | 325 | 200 | 200 | 0 | 0 | 0 |
| Overall Total | 601 | 626 | 601 | 575 | 550 | 275 | 275 | | | |

Table 6-9 Bilateral agreements with neighboring utilities - Winter season capacity totals by region

Capacity Balance Determination

The difference in the coincident peak demand forecast plus other obligations (such as non-member sales, losses, and reserves, less Basin Electric's system-wide load management) and existing and committed generating resources along with purchases, define the load and capability of the Basin Electric system which shows the amount of capacity that Basin Electric is long (surplus) or short (deficit).

Since Basin Electric's member systems reside in four different assessment/planning areas on both the eastern and western interconnection and there is limited capability in moving power between the systems, Basin Electric further narrows its view on load and capability to these four assessment areas on both the eastern and western systems separately. The four assessment areas are: in the western interconnection there is the Northwest Power Pool (NWPP) and the Rocky Mountain Reserve Group (RMRG), and in the eastern interconnection there is the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP). In MISO, there is further segregation into 10 zones known as Local Resource Zones (LRZ), in which Basin Electric's members have loads in LRZ 1 and LRZ 3.

In the western interconnection Basin Electric has the rights to transfer up to 240 MW from the RMRG system across the Rapid City and Stegall DC Ties into the eastern interconnection into Basin Electric's system in SPP. Because of how much surplus capacity Basin Electric has in the RMRG system, we plan to fully utilize those west to east transfer capabilities for the foreseeable future. Figure 6-16 shows Basin Electric's RMRG system summer season surplus capacity both with and without the impacts from being able to transfer capacity across the Rapid City and Stegall DC Ties into SPP.

RMRG System Summer Surplus Capacity

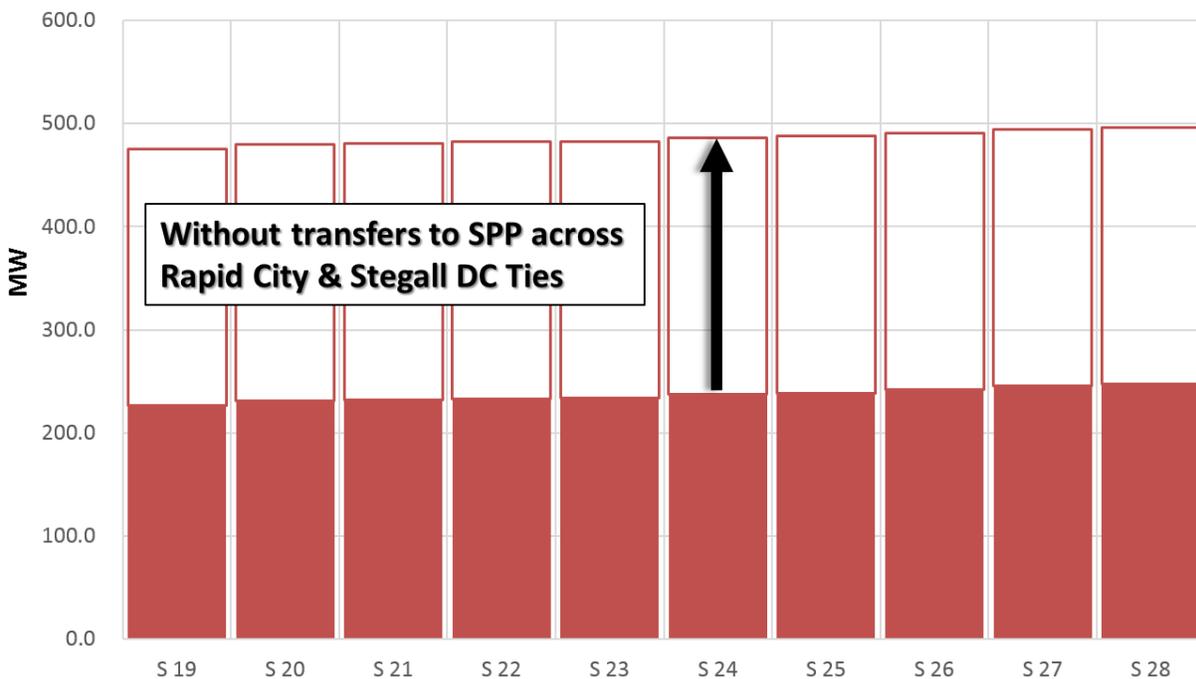


Figure 6-16 RMRG System Summer Surplus Capacity

Figure 6-17 shows Basin Electric’s NWPP system summer season surplus capacity. Basin Electric has the rights to transfer up to approximately 127 MW from the SPP system in the eastern interconnection across the Miles City DC tie into the NWPP system in the western interconnection. With the ability to transfer power east to west from SPP into NWPP, Basin Electric is not expecting to be deficit in NWPP until 2022 at which time approximately 50 MW of additional capacity would get us through 2025 or a little over 100 MW would get us through the study period.

NWPP System Summer Surplus Capacity

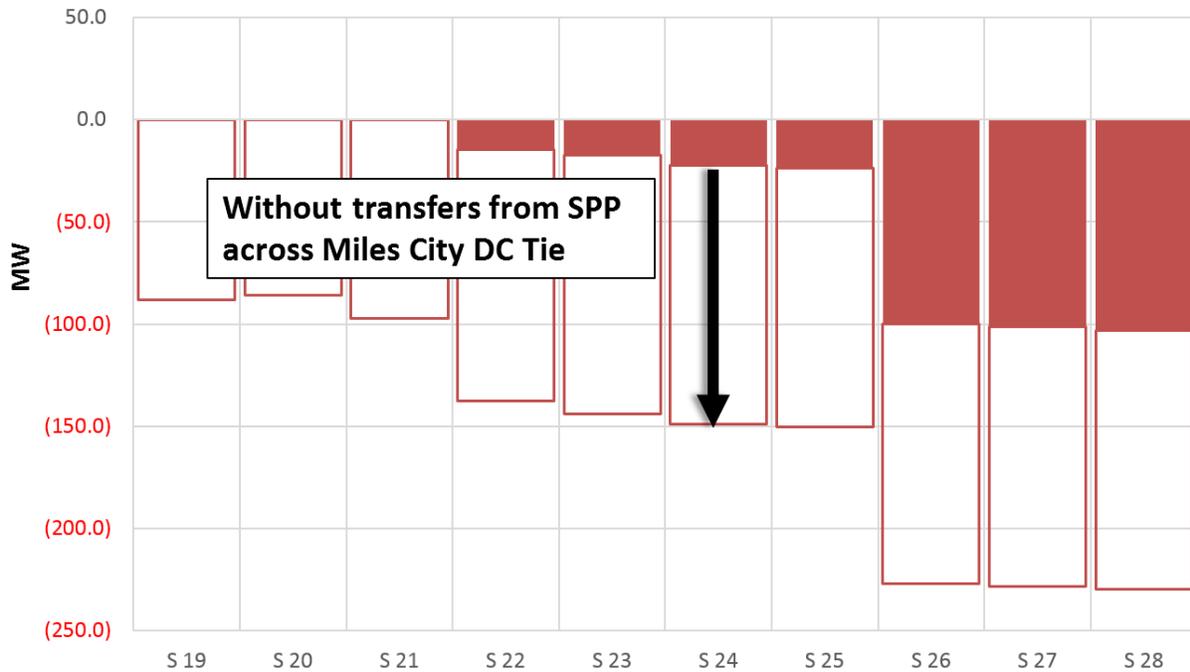


Figure 6-17 NWPP System Summer Surplus Capacity

Basin Electric’s Eastern System can be broken into two areas, SPP and MISO. Figure 6-18 through Figure 6-20 shows Basin Electric’s systems in the Eastern Interconnection.

In MISO, there is further segregation into 10 zones known as Local Resource Zones (LRZ), in which Basin Electric’s members have loads in LRZ 1 and LRZ 3. Figure 6-18 below shows Basin Electric’s MISO LRZ1 system summer season surplus capacity. Basin Electric’s MISO LRZ 1 system is shown to be deficit nearly 100 MW in 2023 and 2024 when some of our bilateral purchases in the region are expected to end and the deficit grows more substantial up to approximately 300 MW. This deficit is forecasted to grow more deficit year over year, to 332 MW by the end of the forecast period.

MISO Zone 1 System Summer Surplus Capacity

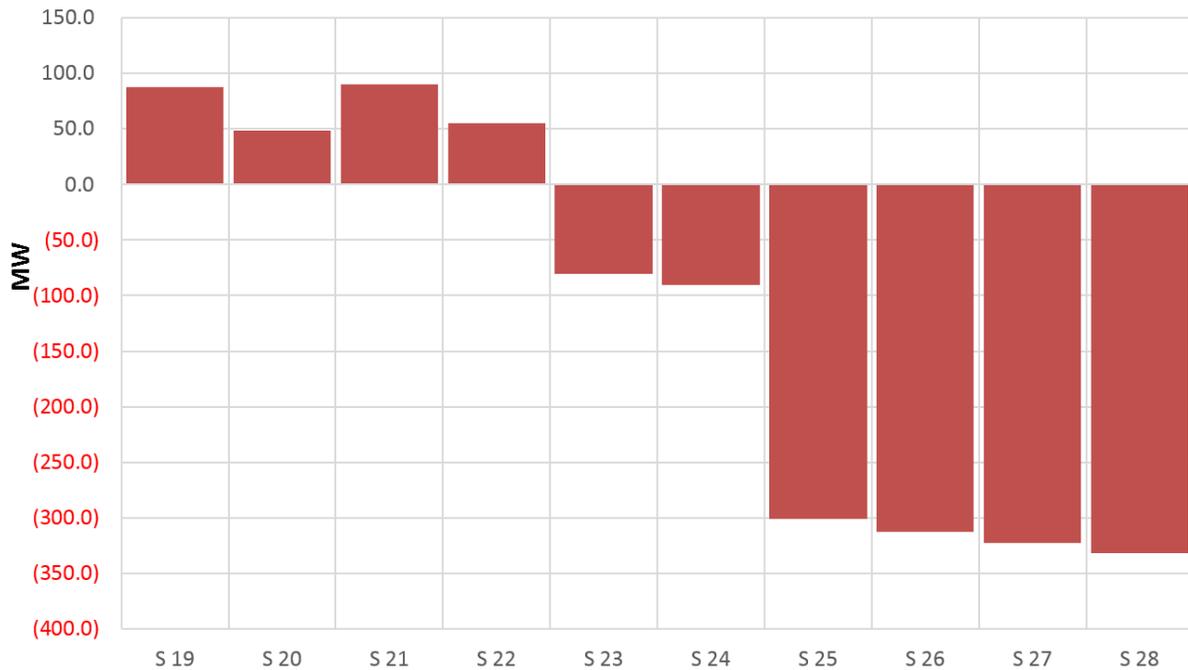


Figure 6-18 MISO LRZ 1 System Summer Surplus Capacity

Figure 6-19 shows Basin Electric’s MISO LRZ 3 system summer season surplus capacity. Basin Electric’s MISO LRZ 3 system is shown to not be deficit until 2026 when our MISO members are expected to gain additional obligations in the region that will need to be supplied by Basin Electric. Basin Electric will continue to monitor the load forecasts and the impacts from these additional obligations.

MISO Zone 3 System Summer Surplus Capacity

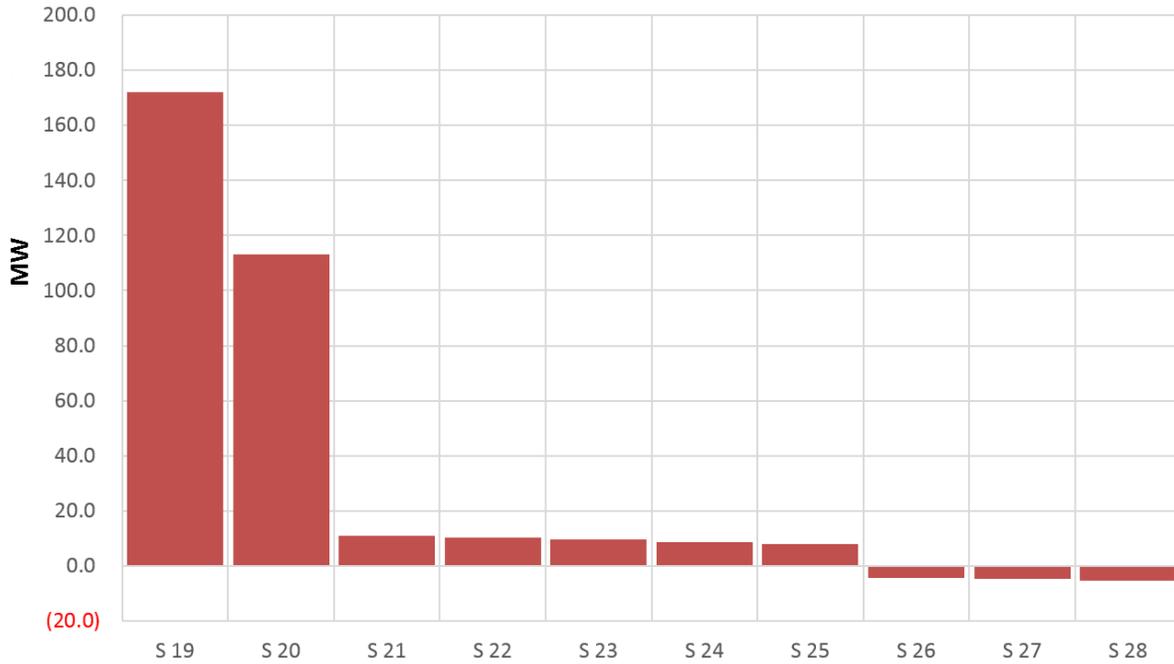


Figure 6-19 MISO LRZ 3 System Summer Surplus Capacity

Figure 6-20 shows Basin Electric’s SPP system. This is the portion of the eastern system showing the greatest growth over the forecasted period. This area encompasses the oil developing region known as the Williston Basin. This graph does include transfers across direct current (DC) ties; the Rapid City DC Tie and the Stegall DC Tie; to transfer power from the west to the east as well as supplying power to Basin Electric’s loads in NWPP across the Miles City DC Tie. The graph shows Basin Electric’s SPP system to be deficit around 200 MW in 2021. This deficit is forecasted to grow more deficit year over year, to more than 450 MW by 2023 and more than 825 MW by the end of the forecast period.

SPP System Summer Surplus Capacity

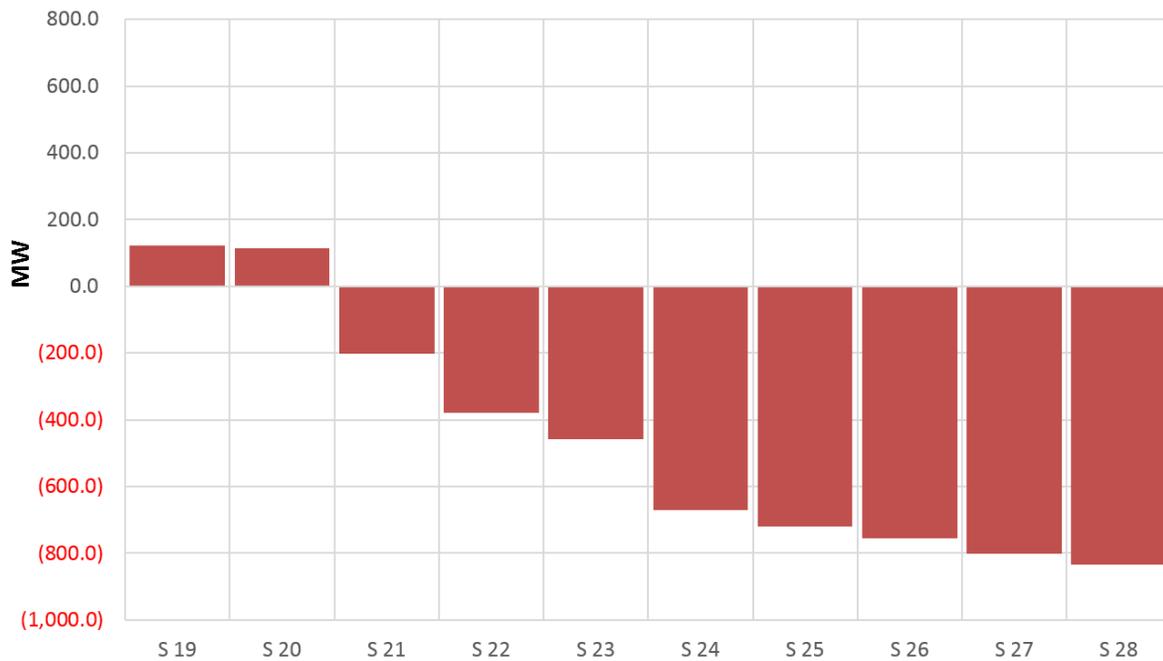


Figure 6-20 SPP System Summer Surplus Capacity

If the DC Tie transfers from the western interconnection to the eastern interconnection across the Rapid City and Stegall DC Ties are unavailable, or there is no surplus on the west to move east, Basin Electric’s SPP system would show up to an additional 240 MW deficit on top of what is shown in Figure 6-20.

Basin Electric continually monitors how the load forecast is developing prior to each season. The summer and winter forecast is monitored for peak load activity. The spring and fall forecasts are monitored to ensure power supply is available during maintenance periods. The load forecast is updated every year to monitor growth across the different sectors the members provide power to. Once the load is determined for the upcoming season, Basin Electric determines if any surpluses are available to market or if power purchases are necessary.

Energy Balance Determination

Basin Electric participates in both the SPP and MISO day two energy markets. These markets use every resource available in its footprint to develop a day-ahead and real-time market dispatch at the lowest price to supply to its member loads. The markets consist of many other products besides energy, such as ancillary services, transmission congestion rights and reliability products.

On the west Basin Electric's RMRG and NWPP areas do not participate in an organized energy market today. The local BA schedules generation to cover the load obligations in that BA. Any external BA sales or purchases are done bilaterally. If there is a mismatch of generation and load, an energy imbalance charge is assessed the short entity.

Figure 6-21 shows Basin Electric's monthly average short and long positions for both on and off peak hours based on our projections and modeled economic dispatch of our units. Hourly dispatch long and short positions are rolled up to monthly totals, which account for why both long and short positions are reported for the same month. The availability of the DC ties to economically transfer power from the eastern to western system and western to eastern system was included in these position views. The netting of these long and short positions gives a clearer picture of the relative net economic energy position, whether truly long or short for the month (Figure 6-22).

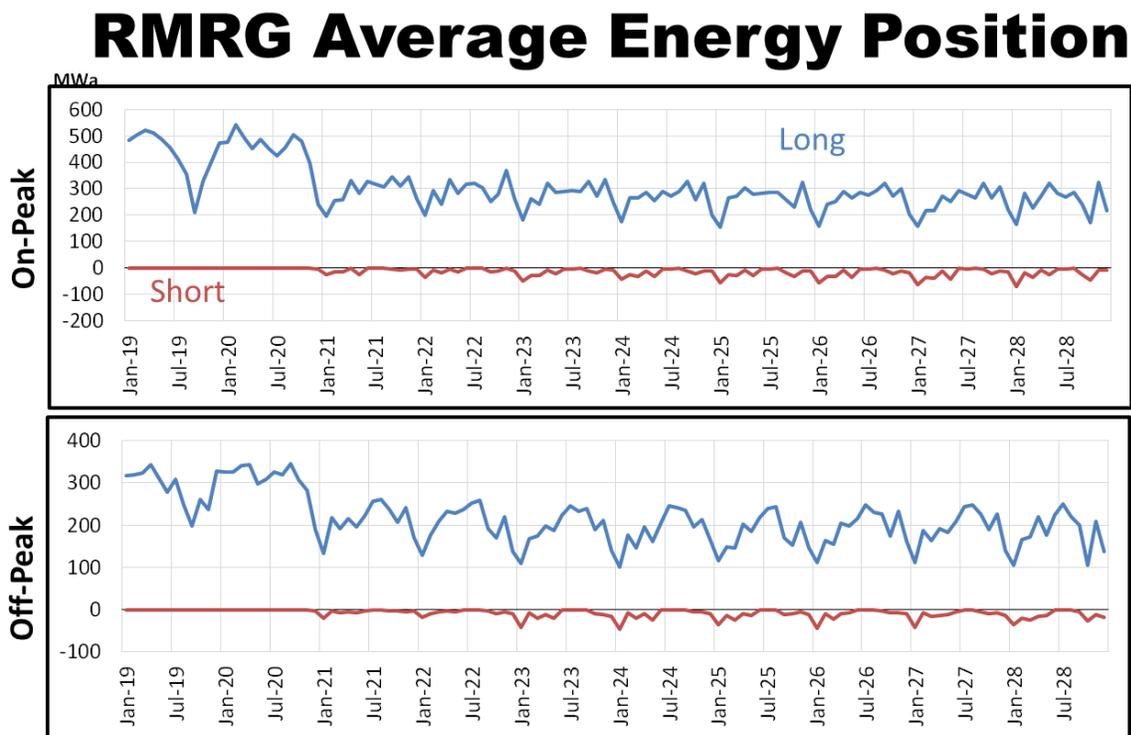


Figure 6-21 RMRG Average Energy Position

Figure 6-22 shows Basin Electric is a net seller of energy throughout the entire study period. Basin Electric currently has an excess of generation in the RMRG region. Since this area is a bi-lateral contractual market, Basin Electric actively looks for counterparties to initiate negotiations for short and long term sales. Today the RMRG area is experiencing a period of very low market pricing, driven by low natural gas pricing, increase hydro generation and an increase in renewable generation. This current pricing state creates issues for Basin Electric to find ways to produce low cost power to serve its own load and have the opportunity to sell its excess generation to counterparties. Basin Electric has rights to move electricity across the west to east intertie facilities at Rapid City and Stegall, giving access to SPP market opportunities. Basin Electric will continue to evaluate ways of moving excess power to other markets to keep our low cost baseload units operating to the extent it makes economic sense in the market.

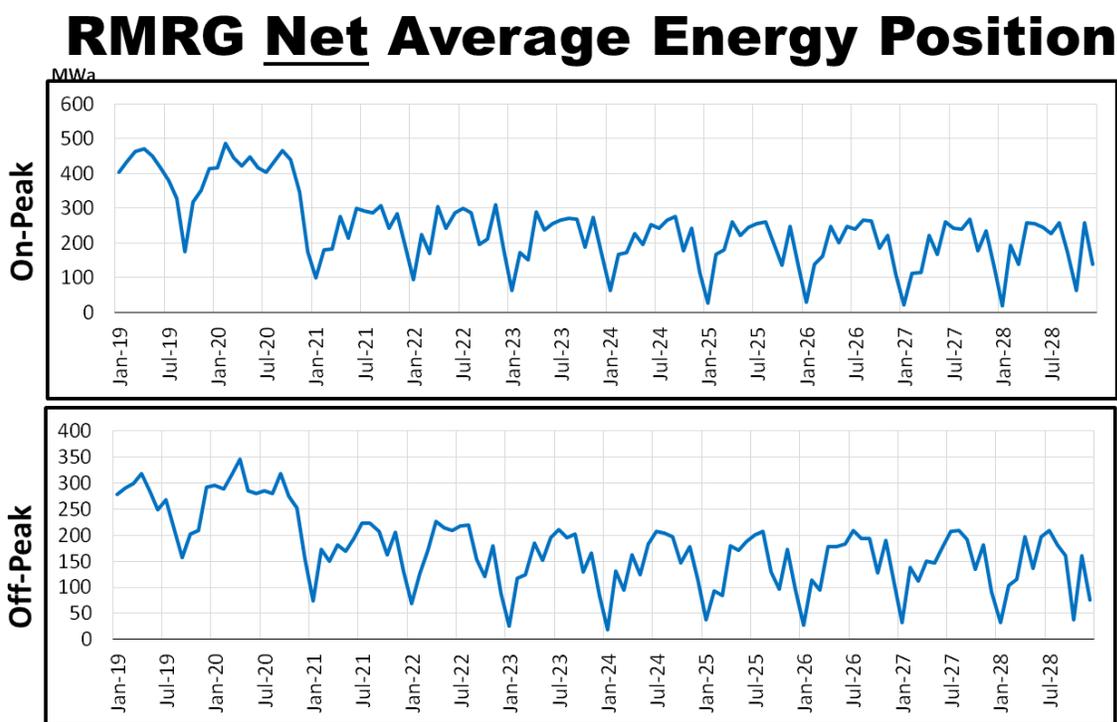


Figure 6-22 RMRG Net Energy Position

Figure 6-23 shows Basin Electric’s monthly average short and long positions for both on and off peak hours based on our projections and modeled economic dispatch of our units. Hourly dispatch long and short positions are rolled up to monthly totals, which account for why both long and short positions are reported for the same month. The netting of these long and short positions gives a clearer picture of the relative net economic energy position, whether truly long or short for the month (Figure 6-24). These charts include the impacts seen from incorporating some of the recommended steps discussed in the conclusions chapter. It can be observed that the recommended step raised our short position to zero through 2025 when some of our existing bilateral purchases end.

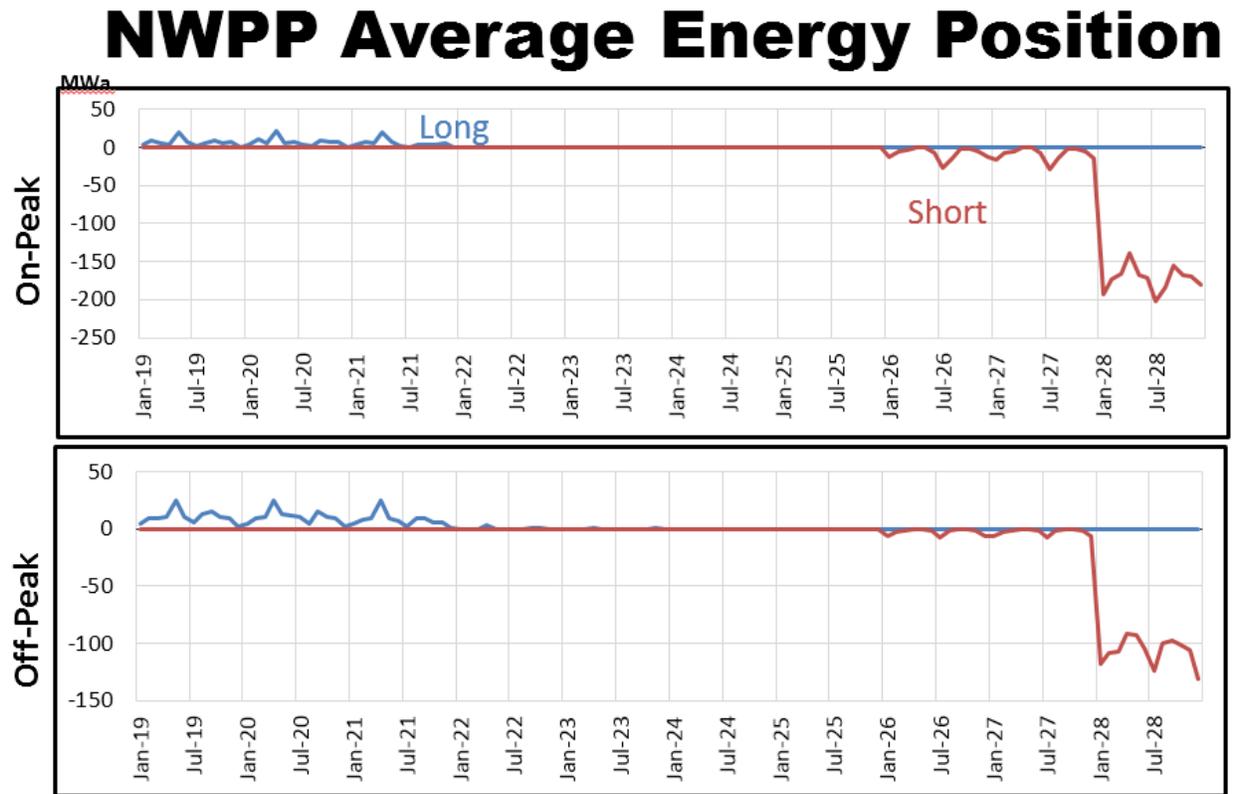


Figure 6-23 NWPP Average Energy Position

Figure 6-24 shows Basin Electric is very balanced in NWPP though through 2025. Basin Electric has energy purchases in NWPP that are set to expire in 2027. Once these contracts expire, Basin Electric will find itself beholden to the market pricing. There is also a growing concern about the possible retirements at the Colstrip Station. Units 1 and 2 are scheduled to retire in 2022, while units 3 and 4 are potentially slated for retirement in 2027⁹. Units 3 and 4 have seen increasing pressure from its western ownership partners to close the facility earlier than proposed, Washington-based Avista Corp, even offering the town affected by the closure \$4.5 million to move away from coal¹⁰. Basin Electric has rights to move electricity across the east to west intertie facilities at Miles City, giving access to west market opportunities and give Basin Electric the ability to serve NWPP load with SPP resources to the extent the market in the NWPP are higher than SPP.

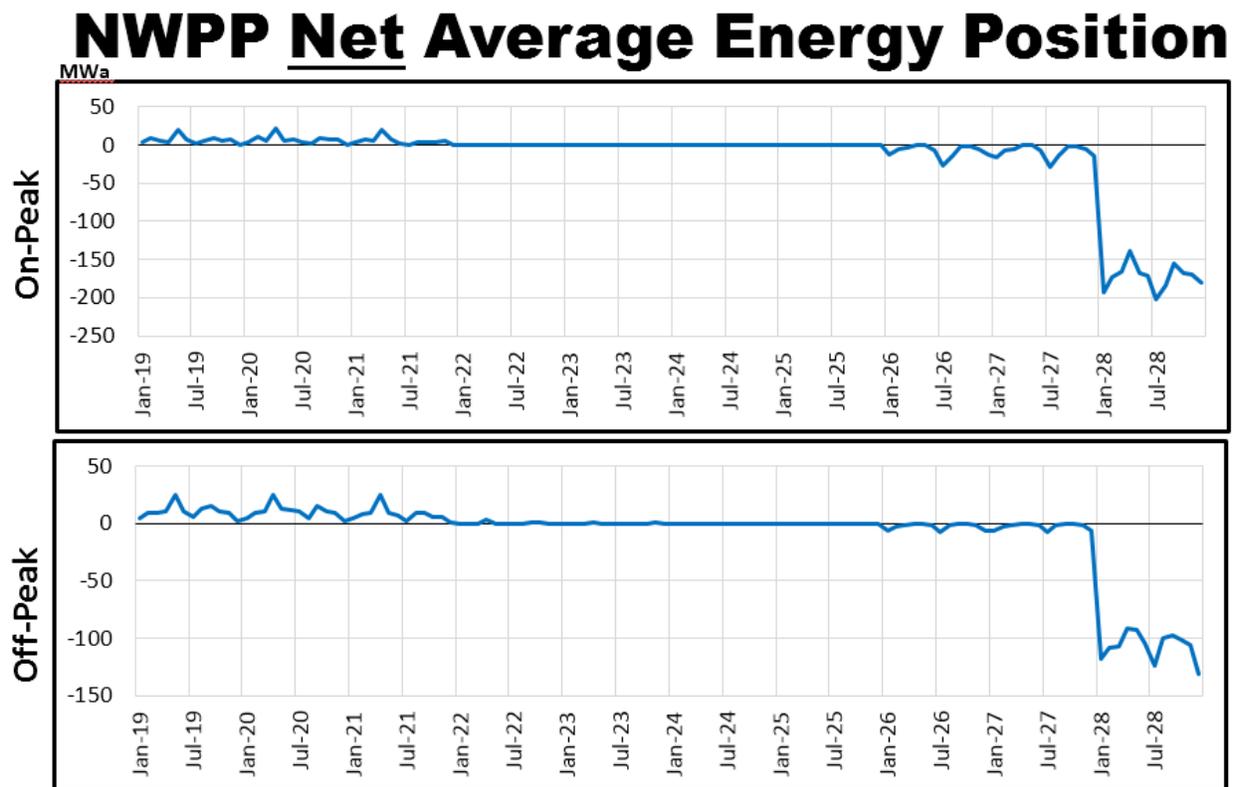


Figure 6-24 NWPP Average Energy Position

⁹ (Drake, 2018)

¹⁰ (Press, 2018)

Figure 6-25 shows Basin Electric’s average monthly short and long positions for both on and off peak hours based on our projections and modeled economic dispatch of our units. Hourly dispatch long and short positions are rolled up to monthly totals, which account for why both long and short positions are reported for the same month. The netting of these long and short positions gives a clearer picture of the relative net economic energy position, whether truly long or short for the month (Figure 6-26).

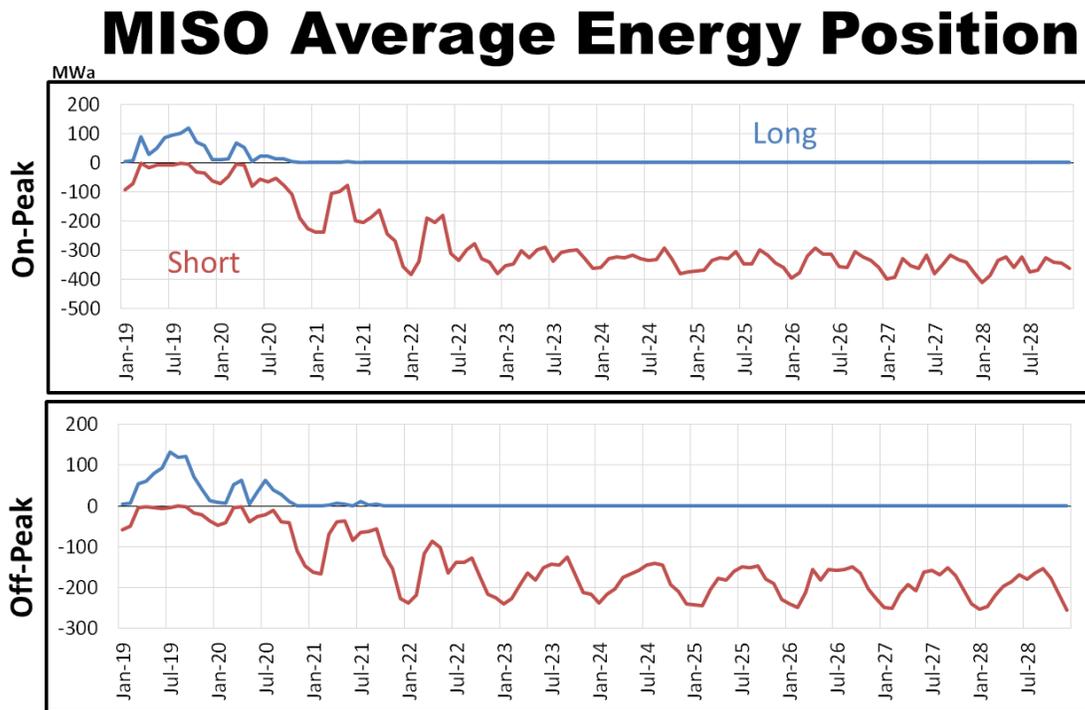


Figure 6-25 MISO Average Energy Position

Figure 6-26 shows Basin Electric is a net seller of market energy today but a buyer in the future. This is because by the end of 2020 Basin Electric has various energy purchases that are set to expire as well as is expecting commercial operations at the Duane Arnold Energy Center to cease, and in 2021 Basin Electric plans on moving our purchased portion of the George Neal South Unit 4 resource back into SPP. Once all of this occurs, Basin Electric will find itself beholden to the market pricing. As this energy position grows so does the risks associated with exposure to the market. Today the MISO market is experiencing a period of very low market pricing, driven by low natural gas pricing and an increase in renewable generation. This current pricing state enables Basin Electric to purchase low cost power to serve load. These risks may need to be mitigated though bilateral contracts for energy or through development of resources to have cost stability in the future as Basin Electric has minimal resources within MISO once certain bilateral contracts end and other generation retires or move to SPP to meet obligations in SPP.

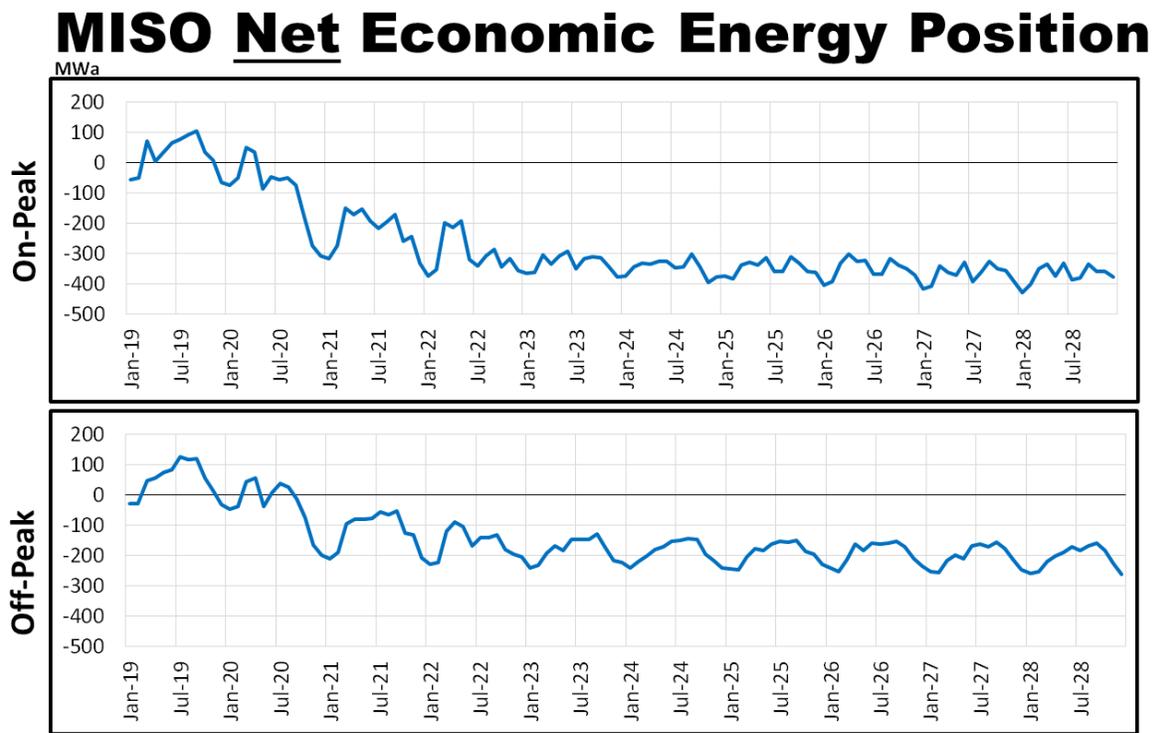


Figure 6-26 MISO Net Energy Position

Figure 6-27 shows Basin Electric’s average monthly short and long positions for both on and off peak hours based on our projections and modeled economic dispatch of our units. Hourly dispatch long and short positions are rolled up to monthly totals, which account for why both long and short positions are reported for the same month. The availability of the DC ties to economically transfer power from the eastern to western system and western to eastern system was included in these position views. The netting of these long and short positions gives a clearer picture of the relative net economic energy position, whether truly long or short for the month (Figure 6-28).

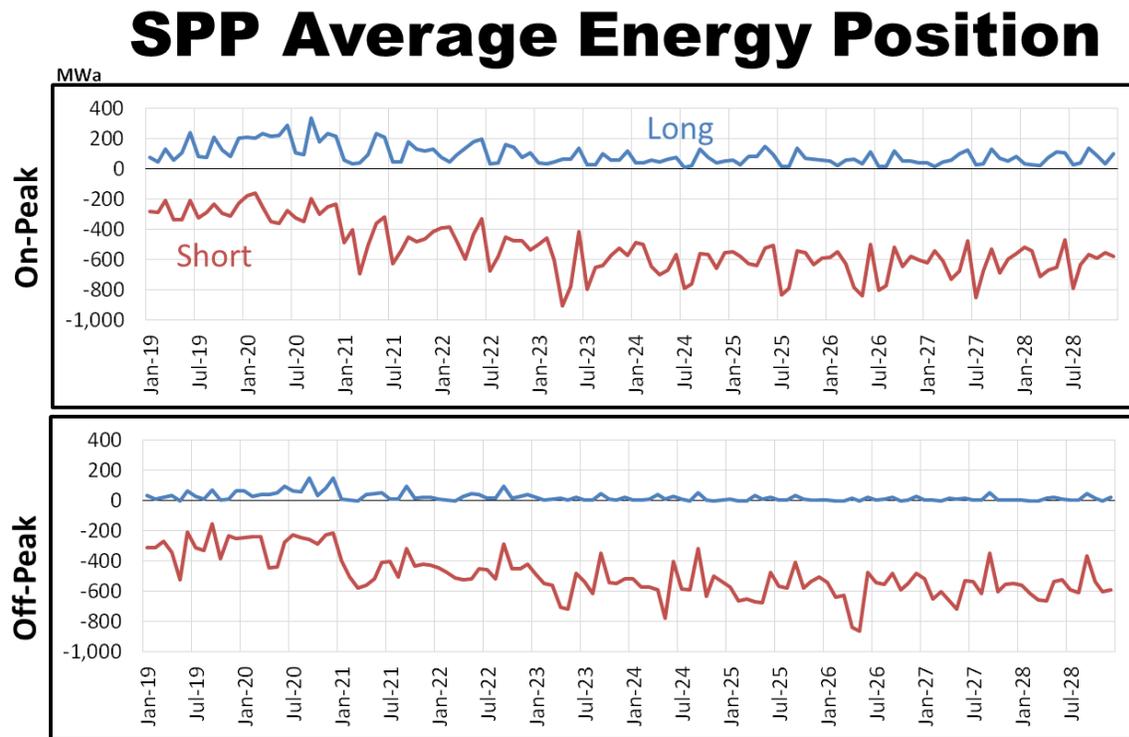


Figure 6-27 SPP Average Energy Position

Figure 6-28 below shows Basin Electric is a net buyer of market energy, increasing over time. As this energy position grows so does the risks associated with exposure to the market. Today the SPP market is experiencing a period of very low market pricing, driven by low natural gas pricing and an increase in renewable generation. This current pricing state enables Basin Electric to purchase low cost power to serve load today.

SPP Net Economic Energy Position

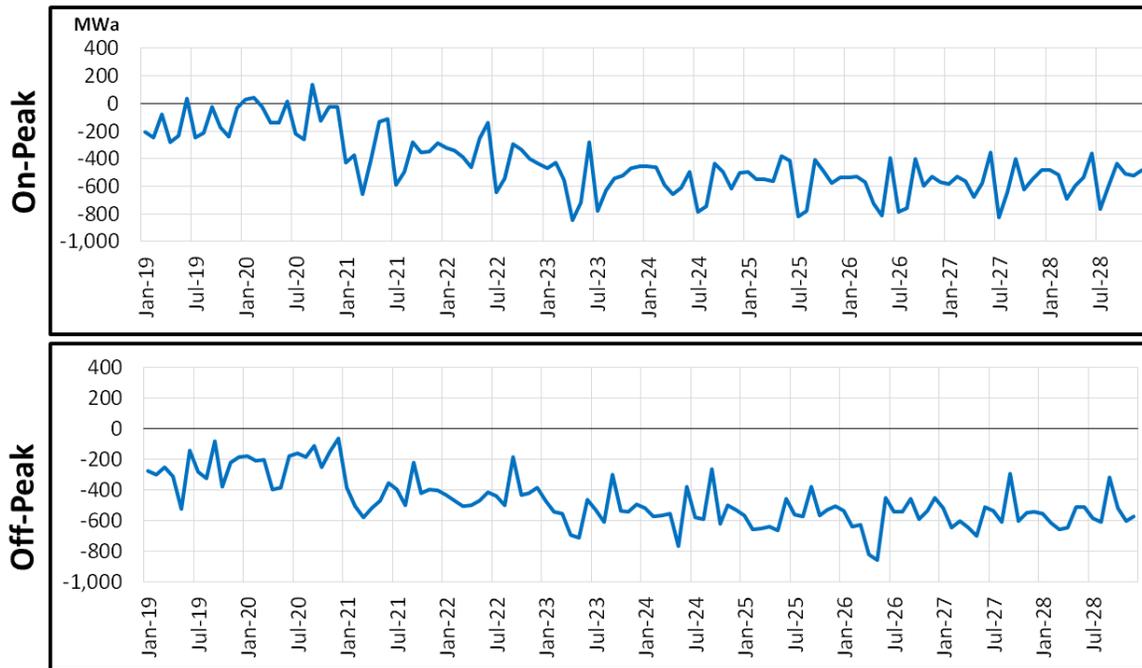


Figure 6-28 SPP Net Energy Position

When this short position seen in Figure 6-28 becomes exaggerated the risk of exposing Basin Electric to a higher degree of purchases vs the possible low cost power in the future has to be analyzed and making sure we have an appropriate backstop of natural gas generation to mitigate the market exposure as seen in Figure 6-29 below. This risk may need to be mitigated through bi-lateral contracts for energy or through development of resources to have cost stability in the future.

SPP Natural Gas Hedge

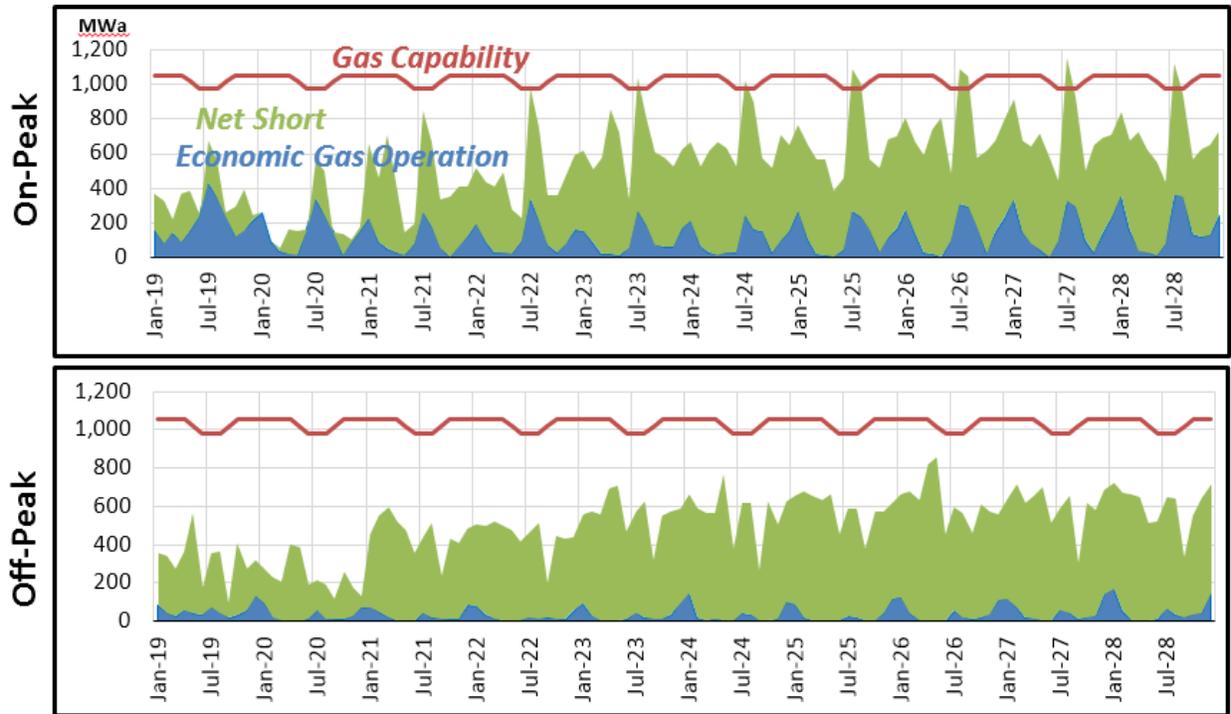


Figure 6-29 Backstop of Natural Gas Generation in SPP to Mitigate Market Exposure

Resource Mix/Diversity

The most economical means of supplying power to a load that varies every hour on an electric power system is to have three basic types of generating capacity available to use:

- a) Base load capacity,
- b) Intermediate capacity, and
- c) Peaking Capacity

Base load capacity runs at its full capacity continuously throughout the day and night, all year round. The output of base load type plants cannot be rapidly decreased or increased to “follow load.” Base load units are designed to optimize the balance between high capital/installation cost and low fuel cost that will give the lowest overall production cost under the assumption that the unit will be heavily loaded for most of its life. Typically, base load capacity units are operated around 80 percent capacity factor or more. Coal-fired steam-cycle power plants, nuclear plants, and hydroelectric plants are examples of base load generation capacity; however, hydro plants that follow load are not base load units.

Intermediate capacity units are designed to be “cycled” at low load periods, such as evening and weekends. The units are loaded up and down rapidly to handle the load swings of the system while the unit is online. Typically, intermediate capacity units are operated between 20 and 80 percent capacity factor range, or between base load and peaking. Technologies for intermediate load plants include oil or gas-fired steam cycle plants, combined cycle plants, some hydroelectric plants, and internal combustion engine generators.

Peaking capacity is only operated during peak load periods and during emergencies. Very low capital/installation costs are very important due to the fact these units are typically not operated very much. The production costs are relatively high due to the high cost and volatility in the price of fuel; this is why these resources are not operated very much. Types of peaking capacity power plants include combustion turbines, internal combustion engine plants, and pumped storage hydroelectric facilities. Typically, peaking capacity is operated under 20 percent capacity factor.

Employing electrical generating resources off all three types, Basin Electric has a diversified mix to meet the membership’s needs in the most economical means. Figure 6-30 helps illustrate the diversification of Basin Electric’s winter season capability portfolio from 2000 to 2018. This has happened because of the significant load growth experienced by our membership and the ability to add additional fuel types to our generating portfolio.

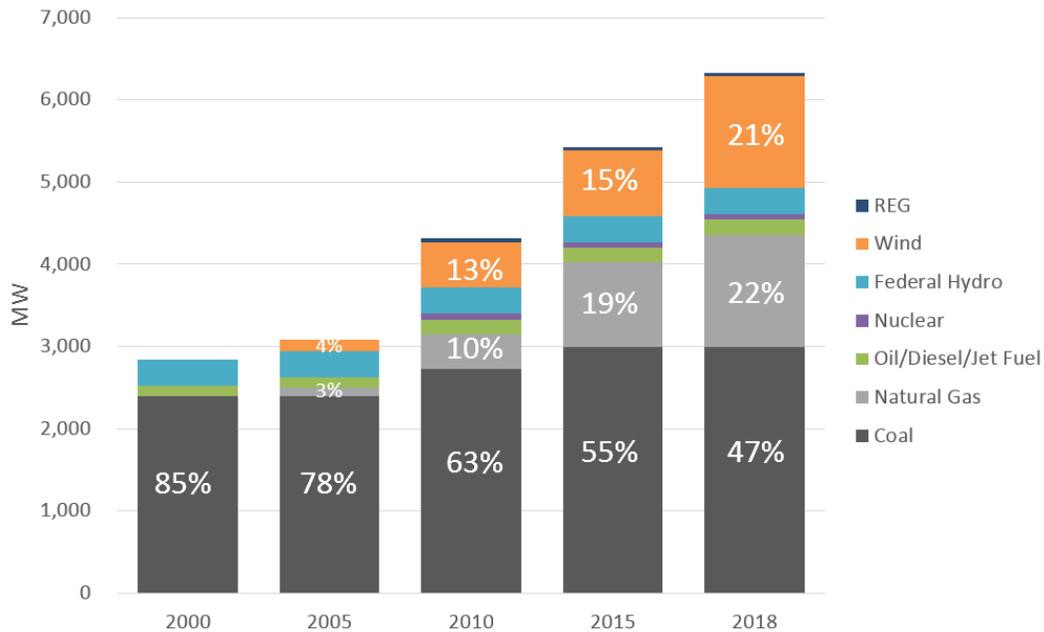


Figure 6-30 Basin Electric Historical Capability Portfolio Diversification

By utilizing resources of all different types, Basin Electric has managed its carbon footprint by incorporating resources in to our portfolio that have either low or no carbon emissions.

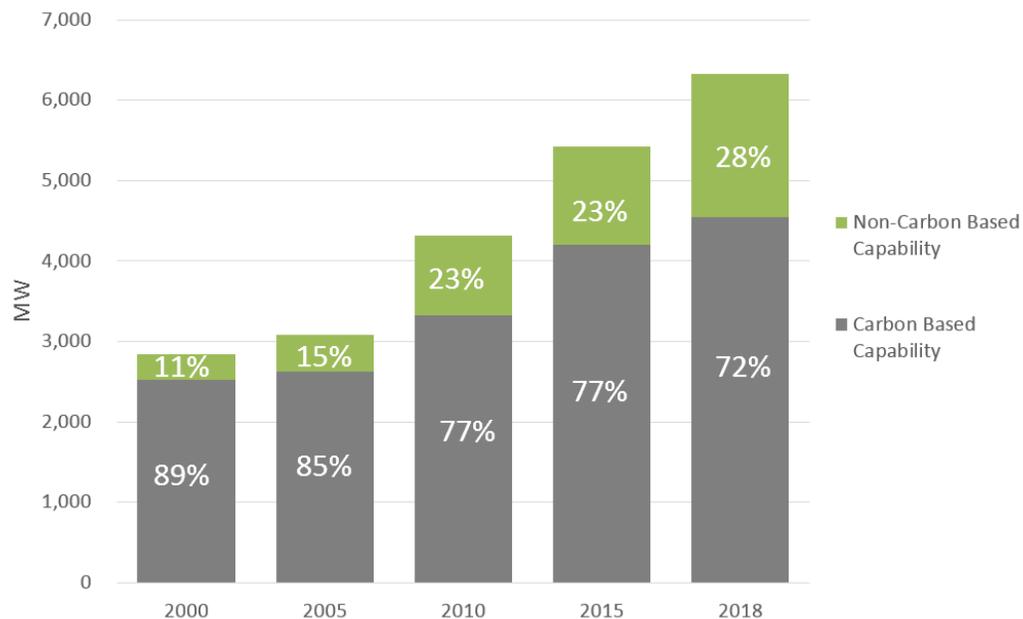


Figure 6-31 Basin Electric Historical Carbon vs. Non-Carbon Diversification

7) Resource Alternatives

Introduction

Basin Electric considers these various forms of generation in evaluating new supply alternatives, along with emerging technologies and other less traditional methods. The specific alternatives addressed in this analysis are listed below.

- Supply Side Resources
 - Renewable Energy Sources
 - Wind
 - Solar
 - Hydroelectric
 - Geothermal
 - Biomass Power
 - Biogas
 - Municipal Solid Waste
 - Fossil Fuel Generation
 - Simple Cycle Combustion Turbine
 - Reciprocating Engine
 - Combined Cycle Combustion Turbine
 - Microturbine
 - Coal Facility
 - Nuclear Power
 - Repowering/Upgrading of Existing Generating Units
 - Purchased Power / Request for Proposal
- Demand Side Management
- Energy Storage
- Transmission Resources
- Market Purchases

Supply Side Resources

Wind

Wind turbines convert kinetic energy from the wind, utilizing turbines to generate mechanical power. Wind power generates electricity without local emissions of any kind. Another advantage of wind power is once a

wind farm is built, the cost of the electricity it generates remains stable because there is no fuel price volatility. Acquiring wind power allows utilities to lock in stable priced electricity for as long as 30 years.

The development of wind power is increasing in many regions of the United States including the areas that Basin Electric and our members serve. Mature markets for the wind generation are shown in the top map of Figure 7-1 in dark blue; these areas represent wind potential capable of a minimum capacity factor of 30% with current generator technology. Basin Electric’s service territory is closely aligned with these areas, as displayed on the bottom map of Figure 7-1.

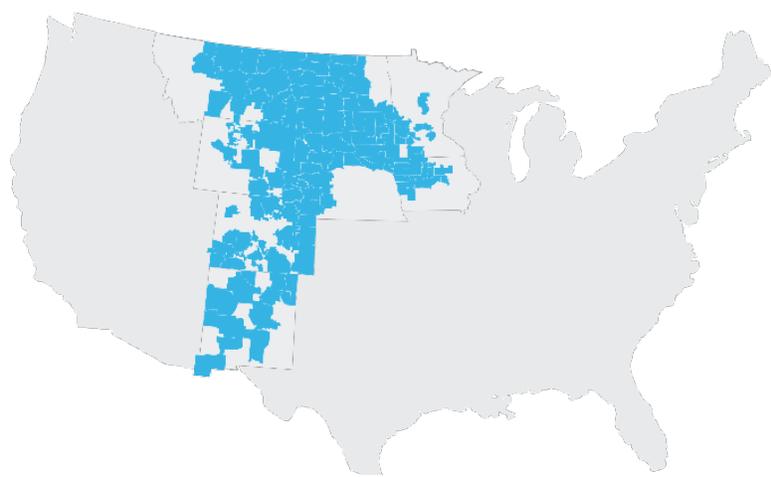
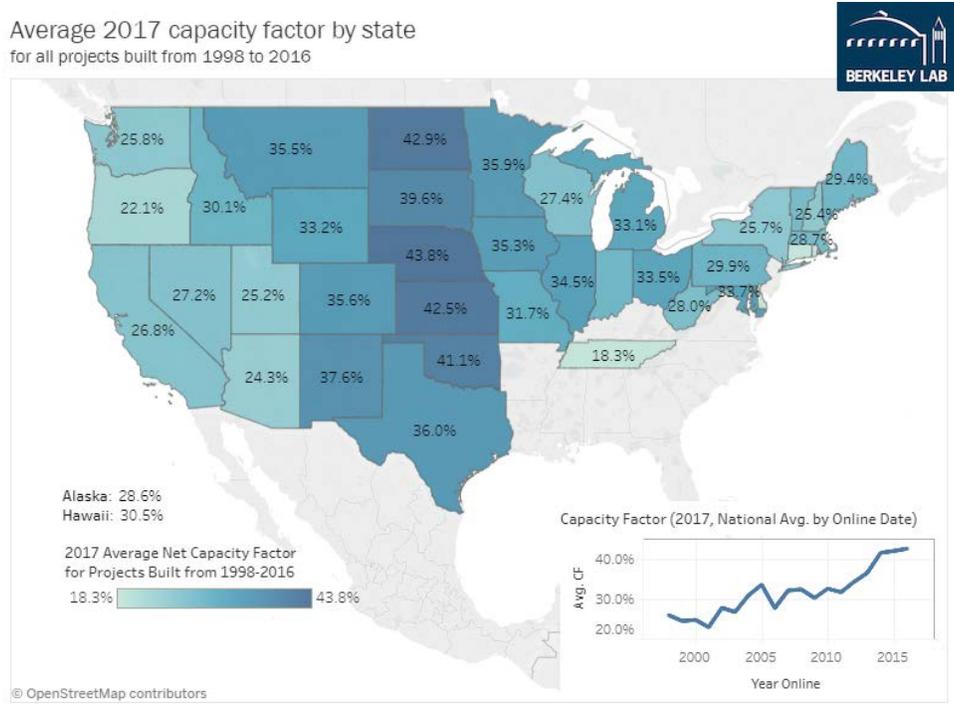


Figure 7-1 U.S. Wind Potential Map and BEPC Service Territory¹¹

¹¹ (Berkley Labs Wind Technology Market Report, 2017)

Wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from class 1 (the lowest) to class 7 (the highest). In general, wind power class 4 or higher can be useful for generating wind power with large (utility-scale) turbines, and small turbines can be used at any wind speed. Class 4 and above are considered good resources. Figure 7-2 is a map of the United States showing the general wind speeds at 100 meter heights.

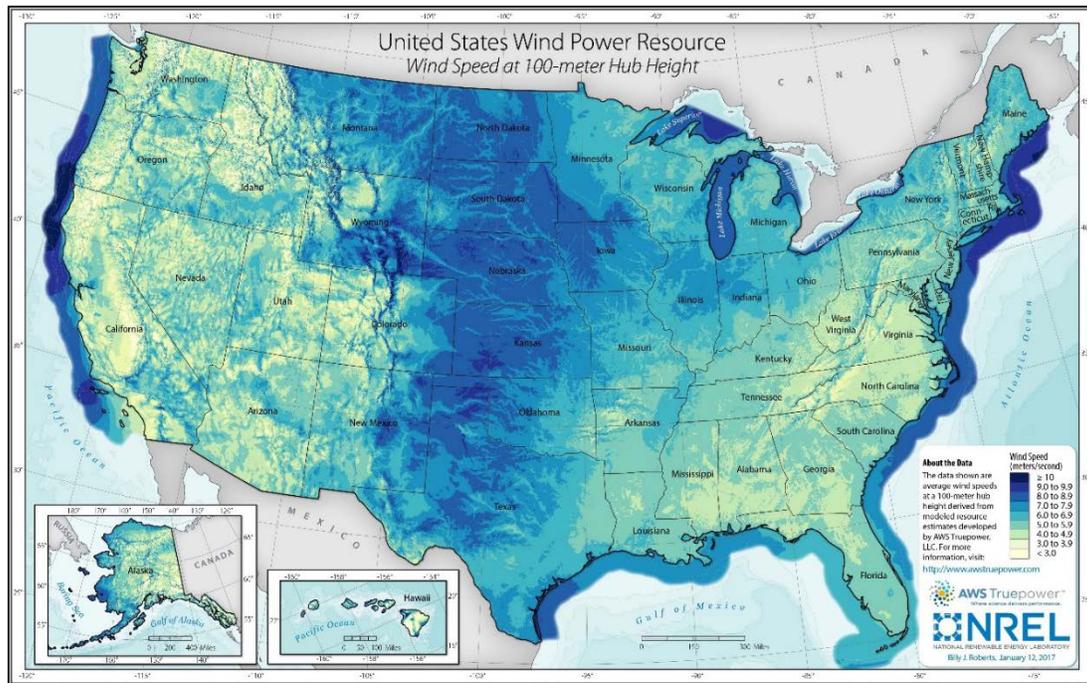


Figure 7-2 U.S. Average Wind Speeds at 100 m¹²

Note there is also significant wind potential located offshore. Offshore wind is a developing market. The first commercial offshore U.S. wind farm was commissioned in 2016 off the coast of Rhode Island. The U.S. Department of Energy projects the United States has the technical potential for 2,000 GW of offshore capacity¹³. However, based on the lack of proximity of Basin Electric’s service territory to coastal areas, offshore wind is not considered as an alternative resource at this time.

Due to the intermittent nature of wind, the economic feasibility of a wind power plant depends on the amount of energy it produces. Capacity factor serves as the most common measure of wind turbine productivity. Estimates of capacity factors range from 30 to 50 percent. Current technology allows for wind site developers to size wind towers to achieve capacity factors as high as 50 percent, primarily by increasing rotor size relative to the size of the generator. Further improvements to implementing larger rotor sizes and taller towers will also allow wind generation to spread to areas with lower average wind speeds.

The MISO system-wide wind resource capacity credit for Planning Year 2018-2019 is 15.2 percent¹⁴. This system-wide MISO wind capacity credit is based on determining the Effective Load Carrying Capability (ELCC) of the intermittent wind resources. A first LOLE simulation is done with the historical-hourly load and same corresponding historical-hour wind resource outputs, and this sets a LOLE benchmark. In a second LOLE

¹² (U.S. DOE WindExchange, 2017)

¹³ (U.S. DOE Offshore Wind Article, 2016)

¹⁴ (MISO Wind Capacity Report, 2018)

simulation the wind resources are removed, and replaced with a trial amount of load reduction that is varied until the same benchmark LOLE result is achieved. The amount of load reduction that achieves the same LOLE result is then the ELCC. As a percentage the ELCC is the resulting load reduction MW divided-by registered wind capacity MW.

The SPP system-wide wind resource capacity credit is a calculated value and varies from wind facility to wind facility. The calculation involves all available hourly net power measured at the system interconnection and the hourly net power output values occurring during the top 10% of load hours for the SPP Member. Then select the hourly net power expected from the facility 85% of the time or greater. Those facilities less than 3 years of commercial operation must include all available data up to 3 years for calculation or can forgo the calculation and submit a 3% resource capacity credit for wind. Facilities with 4 or more years of commercial operation must include all available data up to 10 years for calculation if no calculation is completed the net capability of the resource will be 0 MW¹⁵.

Wind cannot fulfill the long-term generation capacity need for Basin Electric due to its intermittent nature. However, wind has established itself as a very low cost energy source, and can be used to mitigate fuel costs or market purchases as part of a diversified portfolio. Basin Electric will continue to study the effects of wind generation with respect to capacity credits, its effects on other generation resources, market congestion, and its ability to provide a low cost energy option.

¹⁵ (SPP Wind & Solar Accreditation Report, 2017)

Solar

The sun is a near infinite source of energy for our planet. The amount of solar energy transferred to the earth's land areas in one hour is approximately equal to the total U.S. annual energy consumption¹⁶. Current technologies allow for the harnessing of solar energy for heating, lighting, and electricity. The sun's energy can be converted to electricity directly through photovoltaic (PV) cells, or indirectly through the heating of a working fluid. Solar energy varies by location and by the time of year, therefore areas with more direct sunlight for longer periods of time are most suitable for solar generation.

Solar potential is expressed in watt-hours per square meter per day (kWh/m²/day). This is a measure of how much energy radiates over a square meter over the course of an average day. Solar irradiation is typically presented in terms of either direct or global irradiance. The measurement methods are described in Figure 7-3.

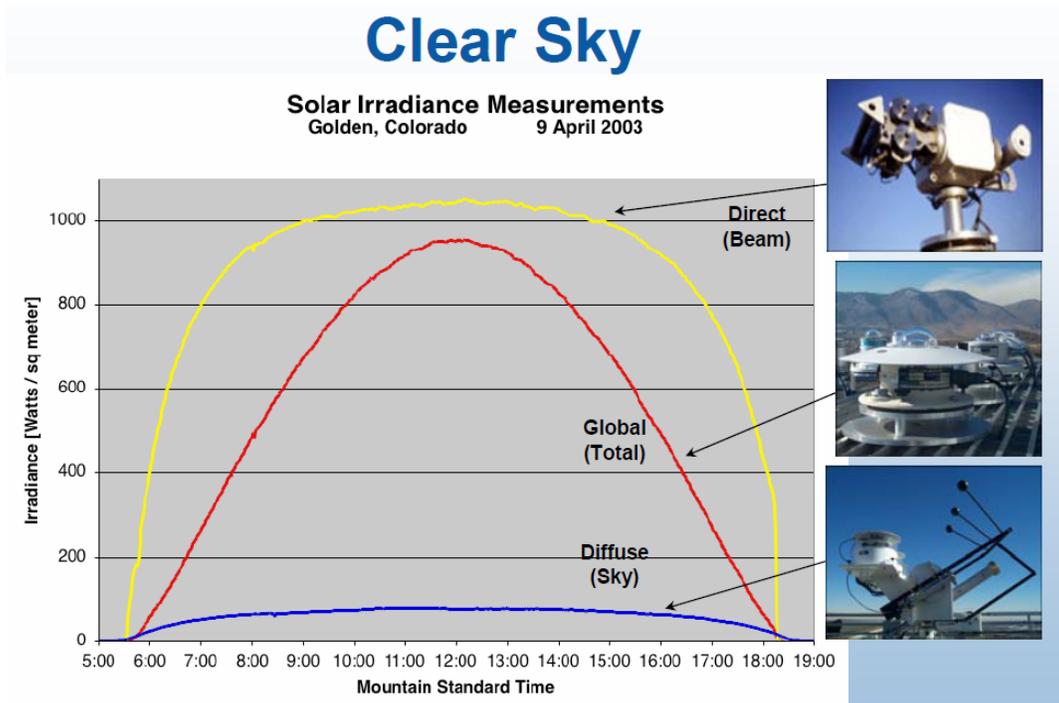


Figure 7-3 Solar Irradiance Measurements¹⁷

¹⁶ (NREL Solar Radiation Measurements, 2004)

¹⁷ (NREL Solar Radiation Measurements, 2004)

Figure 7-4 displays a map of the United States and the amount of solar capability with a flat-plate collector in an area.

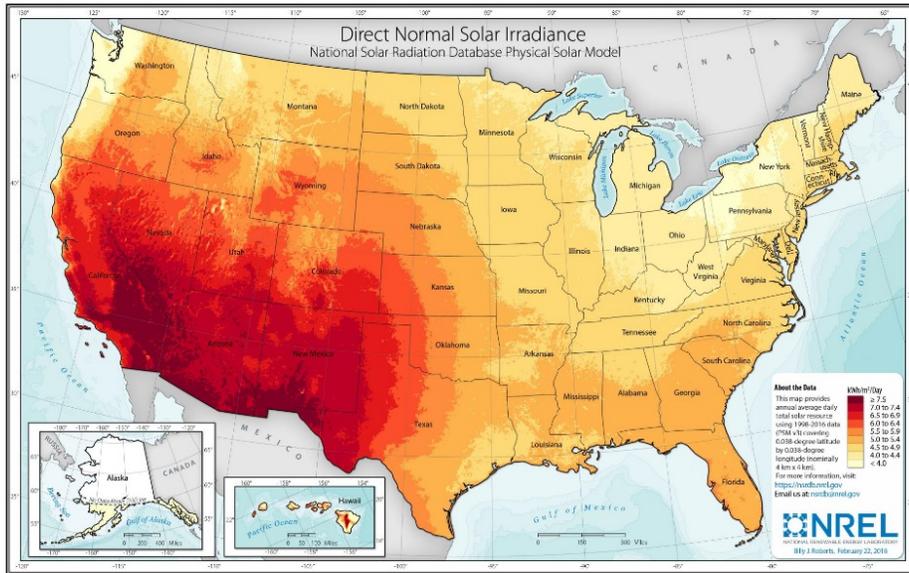


Figure 7-4 Direct Normal Solar Irradiance, kWh/m²/day¹⁸

Figure 7-5 shows a map of the United States and the amount of solar resource capability with a concentrator collector in the area.

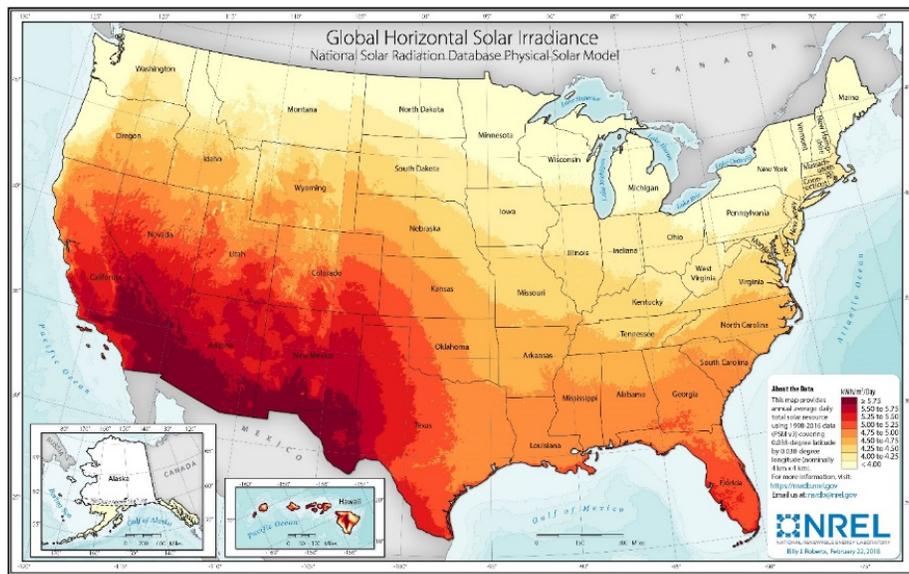


Figure 7-5 Global Horizontal Solar Irradiance, kWh/m²/day¹⁹

¹⁸ (NREL Solar Maps, 2018)

¹⁹ (NREL Solar Maps, 2018)

Solar powered electricity generation is available in two forms. The first is by photovoltaic cells, which are arranged into arrays and built into panels. Solar panels are either installed in an optimized fixed tilt position or rotated by actuators on tracking systems. Solar panels can be arranged into virtually any size installation. Sizes range from small rooftop installations of around 5 kW to large utility scale installations of 1.5 GW. The second form of generation is solar-thermal. These installations redirect and concentrate solar to a central collector, heating a medium such as molten salts which is then used to drive a steam turbine. Solar-thermal plants implement a form of thermal energy storage, and allow for a limited amount of dispatchable power. Solar thermal generation is not considered an economic form of alternative generation at this time.

Due to the intermittent nature of solar power, economic feasibility depends on the amount of energy it produces, its location and the cost. Figure 7-6 shows a map of the United States and the amount of PV solar resource capability. Basin Electric’s service territory generally does not align with areas considered best for solar generation, however the technology could be implemented anywhere. A significant factor for BEPC’s limited experience with solar generation has been the availability of lower cost alternatives, notably wind energy. However, as more wind power emerges within BEPC’s service territory, its value diminishes. Sunshine is not synchronized with the wind, and therefore solar generation may be worth additional consideration moving forward.

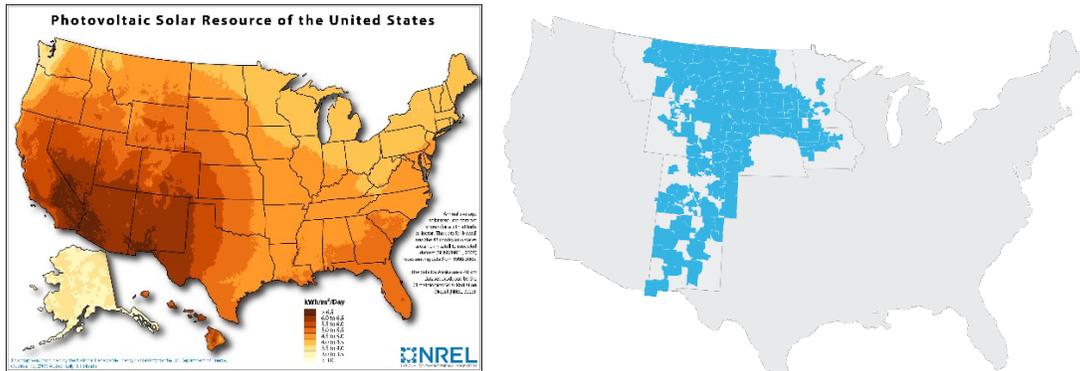


Figure 7-6 PV Solar Potential and BEPC Service Territory²⁰

The main advantages of PV systems are modularity, high reliability, and low environmental impact. These systems have no (or few) moving parts, which means operating and maintenance costs are low. Another obvious benefit of PV systems is that the sun provides abundant and zero fuel costs. However, solar power is not dispatchable in a traditional sense, meaning its output cannot be controlled and scheduled to respond to the variable consumer demand for electricity. It does, however, have the advantage of providing output that has considerable coincidence with natural demand for electricity, driven largely by daytime activities – particularly in the summer when a large amount of electricity is used for air conditioning.

Solar cannot fully satisfy the long-term generation capacity need for Basin Electric due to its intermittent nature and the less than ideal geographical location of Basin Electric’s service territory for solar resources. However, solar costs have significantly fallen over the last decade, and Basin Electric will continue to monitor solar alternatives as a viable energy alternative and how it competes against other options.

²⁰ (NREL Solar Maps, 2018)

Hydroelectric

Hydroelectric power (Hydropower) utilizes the kinetic energy of flowing water. Hydropower is captured and used to power machinery or converted to electricity. Hydropower plants will typically dam a river or stream to store water in a reservoir. The water is released from the reservoir and it flows through a turbine causing it to spin and produce electricity in an attached generator.



Aerial View of Oahe Dam on Lake Oahe near Pierre, SD ²¹

Another type of hydroelectric power plant, referred to as a pumped storage plant, has the capacity to store energy. The water flows through (forward) a generator to a lower reservoir to produce electricity. Later the generators turn the turbines backward, and cause the turbines to pump water from the lower reservoir to an upper reservoir, where the energy (water) is stored. To use the energy, the water is released from the upper reservoir back down to the lower reservoir which turns the turbines forward and activates the generators to produce electricity. The main efficiency in using this process is to pump water up to the upper reservoir during off-peak time and then release the water to flow down through the generators during on-peak times.

²¹ (Lake Oahe, n.d.)

Hydropower is the nation’s leading renewable energy source, accounting for 63 percent of the nation’s total renewable electricity generation. Figure 7-7 shows the amount hydropower per year compared to other forms of renewable electric generation.

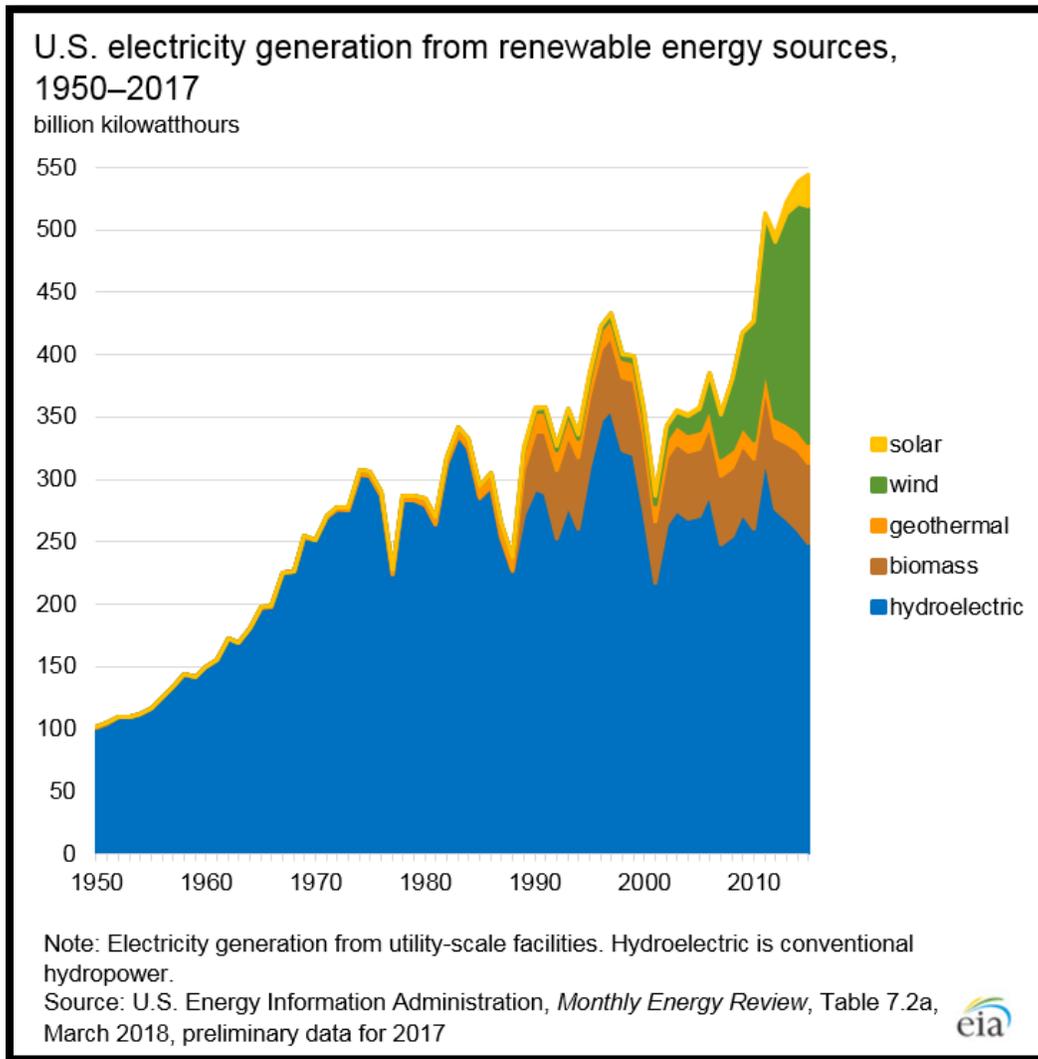


Figure 7-7 U.S. Electricity Generation from Renewable Sources²²

²² (EIA U.S. Energy Explained, 2017)

The amount of hydropower resource varies widely among states. To have a viable hydropower resource, a state must have both a large volume of water and a significant change in elevation. In 2017 there was 80,058 MW of hydropower capacity producing about 300 billion kWh of generation for the year²³. Figure 7-8 shows hydropower production in the United States. The northwest and western states have the highest potential for hydropower. Most dams were not built for hydropower, instead, they were built for irrigation and flood control. The EIA estimates 12,000 MW of potential hydropower capacity available.

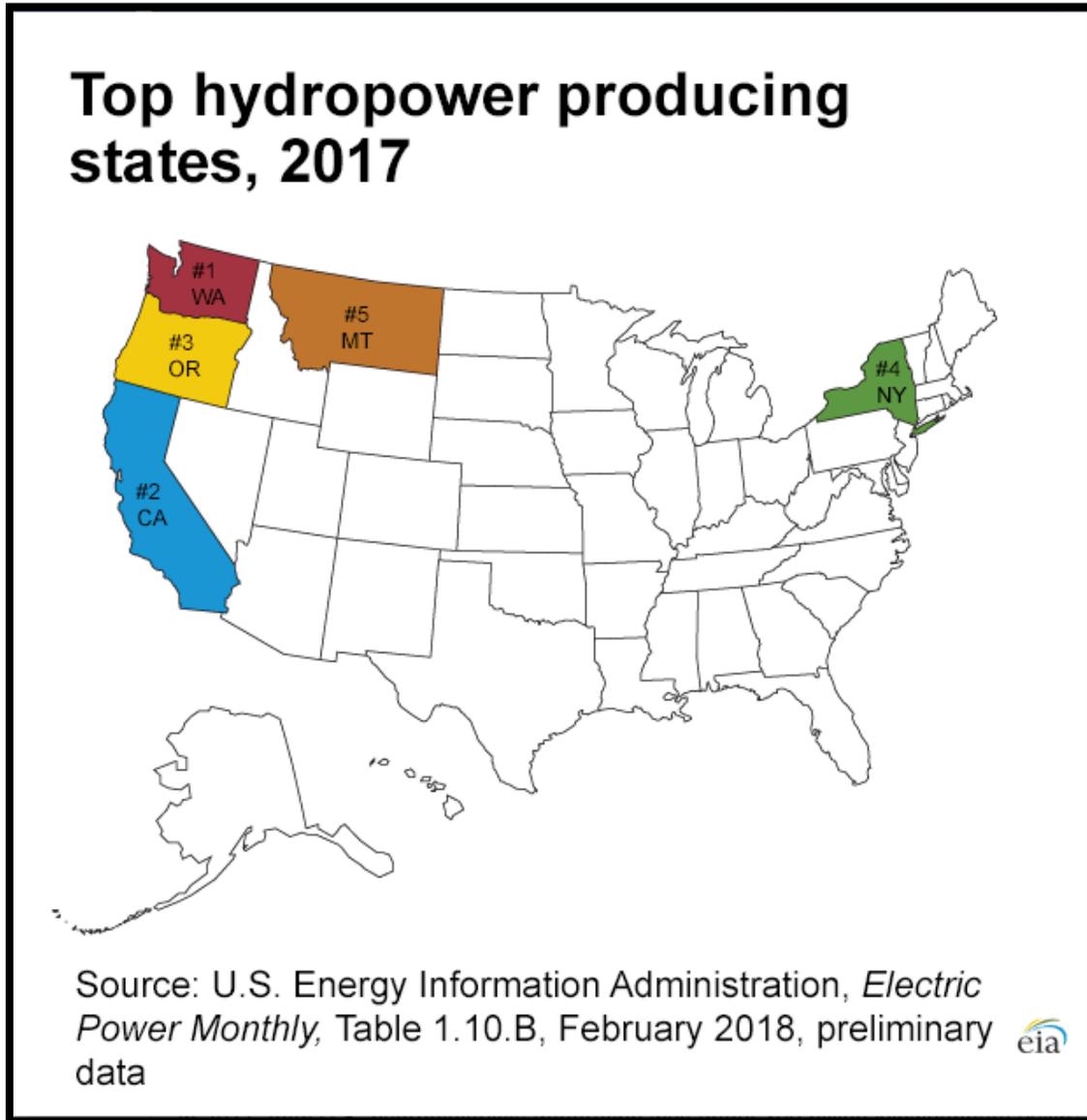


Figure 7-8 Hydropower in the United States²⁴

²³ (EIA Hydro Energy Explained, 2017)

²⁴ (EIA Where Hydro Energy Explained, 2017)

Table 7-1 shows the total hydropower by state for the Basin Electric’s Service Territory for 2017 and 2016. The largest producer of hydroelectric power in Basin Electric’s is the state of Montana. The largest changes from 2016 to 2017 of hydroelectric power were seen in the states of North Dakota and Nebraska.

| Total All Sectors (Thousand Megawatthours) | | | |
|---|-------------|-------------|-----------------|
| State | 2017 | 2016 | % Change |
| Minnesota | 1,258 | 1,209 | 4.1 |
| North Dakota | 2,582 | 1,912 | 35.0 |
| South Dakota | 5,256 | 4,806 | 9.4 |
| Montana | 10,946 | 10,083 | 8.6 |
| Iowa | 1,034 | 917 | 12.8 |
| Nebraska | 1,489 | 856 | 73.9 |

Table 7-1 Total hydropower in Basin Electric Service Territory States²⁵

There are different categories of hydropower facilities: impoundment hydropower, diversion hydropower, run-of-river hydropower, microhydropower and pumped-storage hydropower. Most hydropower facilities are built through federal, state, or local agencies and are part of a multipurpose project. In addition to producing electricity, the multipurpose project may include for flood control, water supply, irrigation, transportation, recreation, or wildlife habitat and refuges. In fact, only 2.9% of dams are built for hydroelectric generation according to the Federal Emergency Management Agency (FEMA) as seen in Figure 7-9.

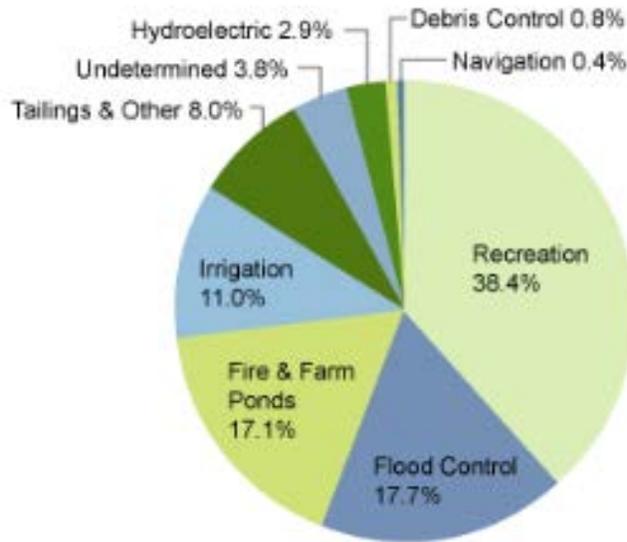


Figure 7-9 Primary Purpose or Benefit of U.S. Dams²⁶

²⁵ (EIA Utility Scale Hydro Table, 2017)

²⁶ (FEMA Dam Benefits, 2018)

Impoundment hydropower facilities use a dam to store water in a reservoir. Water is released from the reservoir to meet changing electricity need, maintain a constant water level, or for environmental purposes such as preserving wildlife habitat.

Diversion hydropower is the diversion of a portion of the river or stream through a canal or penstock (but may require a dam) to the turbines. The weather and seasonal variation in the river's water level can result in significant fluctuations in power production.

Run-of-River hydropower utilizes the flow of water within the natural range of the river, requiring little or no impoundment. Run-of-river plants can be designed using large flow rates with low pressure deltas or small flow rates with high pressure deltas.

Micro hydropower projects produce 100 kilowatts (kW) or less. Micro hydro plants can utilize low or high pressure deltas.

Pumped-storage hydropower facilities have reversing turbines that can pump water from a lower reservoir to an upper reservoir at times when demand for electricity is low and excess electricity is available from other sources on the power grid.

Any new hydropower addition would require major environmental considerations, including the ecology of the natural river system, water quality, alteration of river flows, land alternations, and construction of reservoirs and structures.

According to EIA's Construction cost data, in 2016 256 MW of hydroelectric capacity was added at new plants and 124 MW was added at existing plants at a total cost of about \$2 billion with a weighted average installed cost of \$5,312/kW²⁷. Due to the seasonal nature of hydropower, the average annual capacity factor for most facilities is approximately 40 to 50 percent. Another major issue regarding hydropower is its year-to-year unpredictable nature due to annual rainfall variability.

This type of resource could meet potential intermediate need but Basin Electric has already been approached regarding a pumped hydro storage facility (see Pumped Hydro section under the Energy Storage section below regarding the Gregory County Pumped Storage project). The costs are too high and permitting would be very difficult, therefore Basin Electric is not pursuing new hydroelectric power resources at this time.

²⁷ (EIA Generator Costs, 2016)

Geothermal

Geothermal energy is thermal energy from the Earth's interior where temperatures reach greater than 7,000°F. The heat is brought to the surface as steam or hot water and used to produce electricity or applied directly for space heating and industrial processes. Currently, there is about 3,500 MWs of geothermal electricity in the United States with about 1,200 MW planned²⁸.

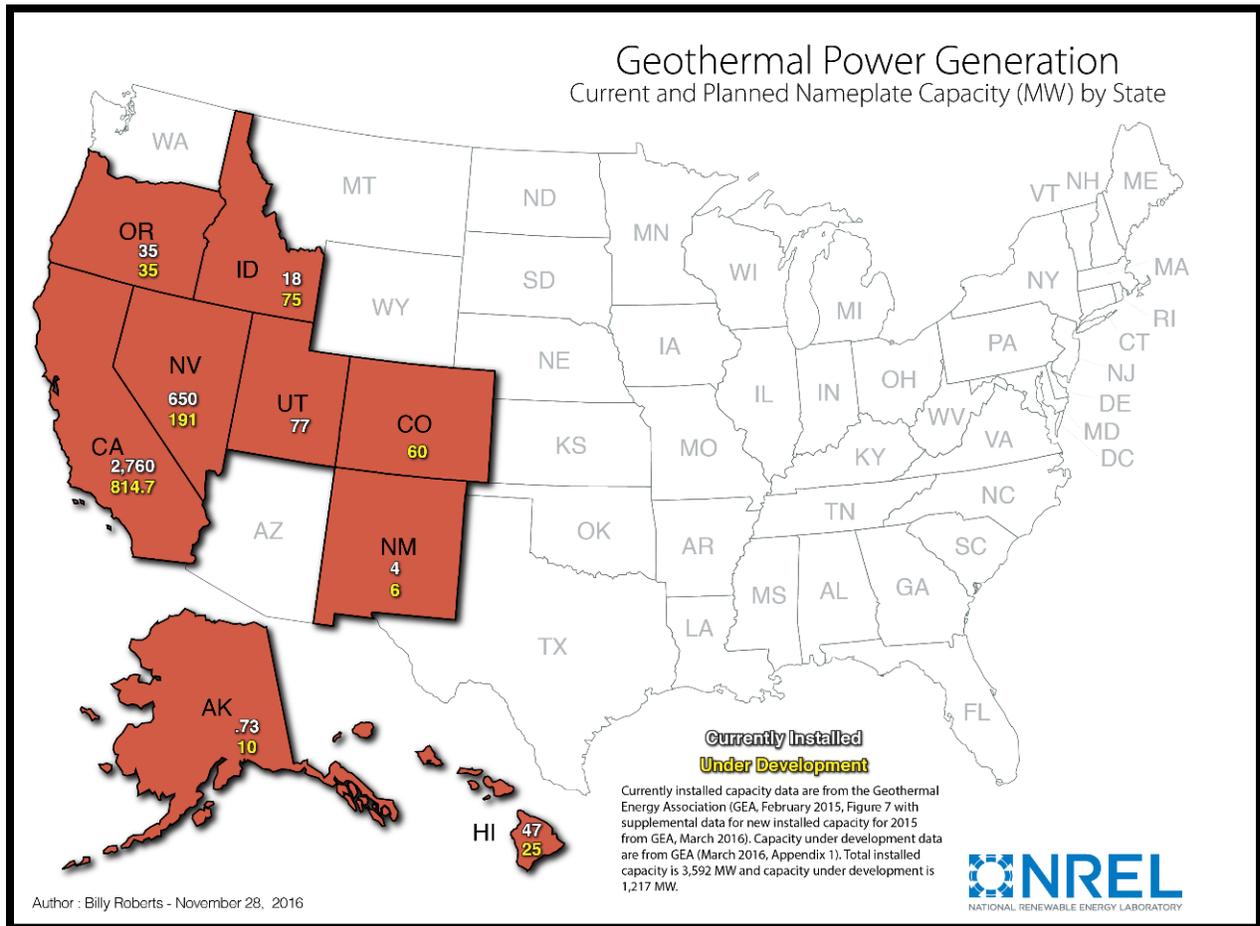


Figure 7-10 Geothermal Power Installed and Planned Capacity²⁹

²⁸ (NREL Geothermal Capacity, 2016)

²⁹ (NREL Geothermal Capacity, 2016)

There are three types of geothermal energy. The first is power generation (or electric), which utilizes steam turbines using natural steam or hot water flashed to steam, and binary turbines produce mechanical power that is converted to electricity. The second is a direct use application where a well brings heated water to the surface; a mechanical system delivers the heat to the space or process; and a disposal system either injects the cooled geothermal fluid underground or disposes of it on the surface. The third and most rapidly growing use for geothermal energy is geothermal heat pumps, which use the earth or groundwater as a heat source in winter and a heat sink in summer or otherwise known as a device which transfers heat from the soil to the house in winter and from the house to the soil in summer. Figure 7-11 below shows geothermal resources throughout the United States.

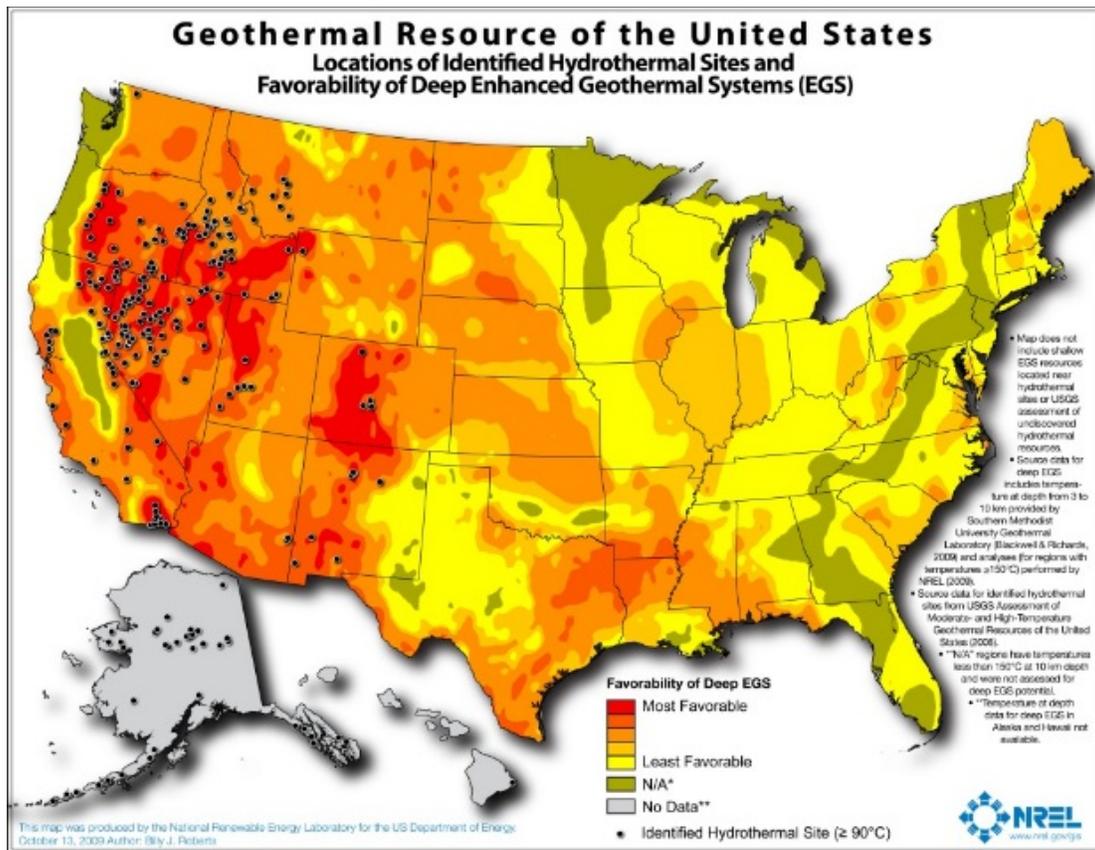


Figure 7-11 Geothermal Temperatures for Resources in the United States³⁰

It is generally said that electric use would be 200°C or greater, direct use would be 150°C to 200°C and heat pumps would be 100°C to 150°C . North Dakota has low to moderate temperature resources that can be tapped for direct heat or for geothermal heat pumps. However, electricity generation is not possible with these resources. South Dakota has a small area in the south central portion of the state that has high-temperature resources that are suitable for electricity generation. The entire state has resources suitable for direct use and heat pump applications. Montana has high-temperature resources that are suitable for electricity generation as well as direct use and heat pump applications, but many of these areas are located with the boundary of Yellowstone National Park. Minnesota has vast low-temperature resources suitable for

³⁰ (NREL Geothermal Capacity, 2016)

geothermal heat pumps. Minnesota does not have sufficient resources to use the other geothermal technologies. Nebraska has low to moderate temperature resources that can be tapped for direct heat or for geothermal heat pumps. However, electricity generation is not possible with these resources. Iowa has vast low-temperature resources suitable for geothermal heat pumps, but does not have sufficient resources to use the other geothermal technologies.

Geothermal power plants are very reliable when compared to conventional power plants. Geothermal power plants will typically have an availability factor of 95 percent or more and their capacity factor is highest among all types of power plants. Steam plants use very hot (more than 300°F or roughly 150°C) steam and hot water resources. Binary plants use lower-temperature, but much more common, hot water resources (100°F to 300°F or approximately 40°C to 150°C).

Geothermal electric power capital costs typically around \$2,500/kW with operating and maintenance cost ranging from \$0.01 to \$0.03 per kWh³¹.

Due to the limited locations that electric generation from geothermal is available within Basin Electric's service territory, this alternative is not being pursued any further at this time. However, if an entity came to Basin Electric with a proposed project, Basin Electric would fully evaluate that option and determine if it was a viable option at that time.

Biomass Power

Biomass power (Biopower) is the generation of electric power from biomass resources. These resources include urban waste wood, crop and forest residues, and potentially in the future, crops grown specifically for energy production. Biomass is the second most widely utilized renewable energy behind hydroelectricity. Biomass plants result in very low Carbon Dioxide (CO₂) emissions due to the absorption of CO₂ during the biomass cycle of growing, converting to electricity, and re-growing biomass.

There are four primary types of biomass power systems: direct-fired, co-fired, gasification, and modular systems. The majority of current biomass generation is based on direct-fired combustion in small, biomass-only plants with relatively low electric efficiency, typically in the low 20% range. Most biomass direct-fired combustion generation facilities utilize the basic Rankine cycle for electric power generation, which burns biomass fuel in a boiler to produce steam that is expanded in a Rankine Cycle prime mover to produce power. Currently, co-firing is the most cost-effective technology for biomass. Co-firing substitutes biomass for coal or other fossil fuels in existing coal-fired boilers. Gasification systems are normally coupled with fuel cell. As gasifiers and fuel cell costs come down these systems will become more attractive.

Biomass power growth can also create new markets and employment for farmers and foresters. It can establish new processing, distribution, and service industries in rural communities.

The price of electricity depends on the type of technology used, the size of the power plant and the cost of the biomass fuel supply. Currently, the most economically attractive technology for biomass is co-firing. These projects require small capital investments per unit of power generation capacity. Co-firing systems range in size based on about 10% to 20% of the heat input required from biomass while the remaining is co-fired with coal. However, the cost of biomass fuel is highly dependent on the transportation cost, availability,

³¹ (U.S. DOE Geothermal FAQ, n.d.)

and preparation which often times cannot compete with the cost of coal alone without monetizing the CO₂ emissions reduction benefit.

For biomass to be economical as a fuel for electricity, the source of biomass must be located near where it is used for power generation. This reduces transportation costs. The most economical conditions exist when the energy used is located at the site where the biomass fuel is generated. The following map shows available United States biomass resources by county.

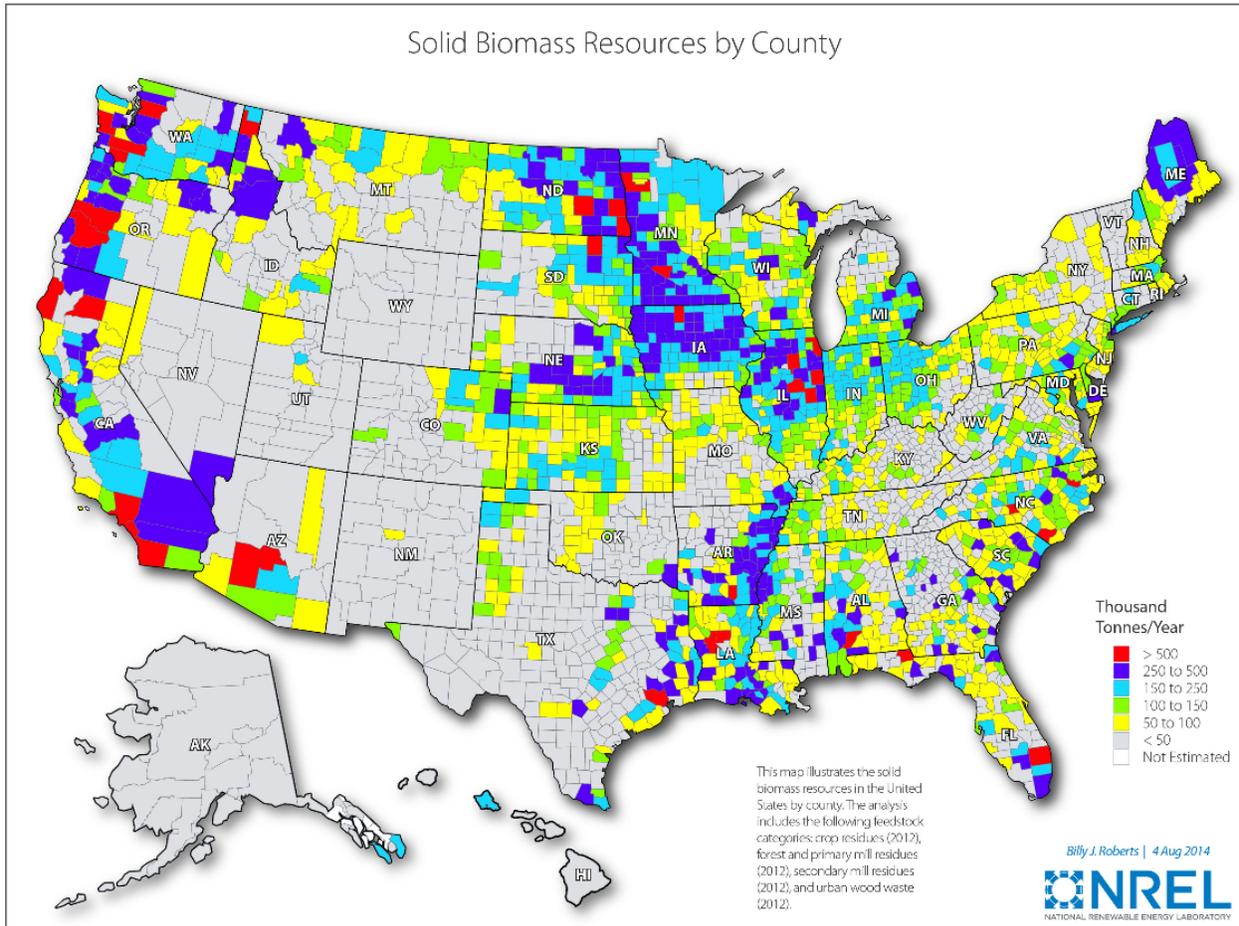


Figure 7-12 Solid Biomass Resources by County³²

Basin Electric has a policy within its rate structure to purchase output from small renewable resources from a member that has either wind, solar or biomass generation facilities located on their respective members systems. Due to this policy, Basin Electric would work with its member systems for this type of renewable power and would not move toward developing the resource itself.

³² (NREL Biomass Maps, 2014)

Biogas

A Biogas power plant is a system where biogas is used to generate electricity. Biogas power plants are a combination of anaerobic digestion systems with associated electricity generators such as gas turbines or gas engines. Feedstock into the biogas power plants must be biodegradable in order to produce methane.

Suitable feedstocks include (but are not limited to):

- Biodegradable waste
- Sewage treatment sludge (primary or raw sludge and/or secondary sludge)
- Slaughterhouse waste
- Food waste
- Farm waste
- Organic component of mixed municipal waste (in mechanical biological treatment)
- Biomass like maize

Anaerobic digestion is the harnessed and contained, naturally occurring process of anaerobic decomposition. An anaerobic digester is an industrial system that harnesses these natural processes to treat waste, produce biogas that can be used to power electricity generators, provide heat and produce soil improving material. There are three stages of anaerobic digestion: hydrolysis, acidogenesis, and methanogenesis. These stages can occur in the same digestion tank or can be controlled independently and optimized according to the requirements of the different bacterial processes.

Biogas is one of the principal by-products of anaerobic digestion and is a gaseous mixture comprised mostly of methane and carbon dioxide, but also contains a small amount of hydrogen and occasionally a trace level of hydrogen sulfide. Biogas can be burned to produce electricity, usually with a reciprocating engine or microturbine. The gas is often used in a cogeneration arrangement, to generate electricity and use waste heat to warm the digesters or to heat buildings. Electricity produced by anaerobic digesters is considered to be green energy

Processing biodegradable waste using anaerobic digestion helps to reduce global warming. The carbon in biodegradable waste is part of a complete carbon-cycle: the carbon released from the combustion of biogas was removed by plants in the recent past, and does not contribute to the global accumulation of carbon in the same manner that fossil fuels do. Furthermore, if this waste was landfilled it would break down naturally and the biogas would escape directly into the atmosphere. Using the biogas for energy is an intermediate use that does not affect the overall cycle. In this way anaerobic digestion is considered to be a sustainable technology and biogas is considered to be a renewable fuel.

Basin Electric has a policy within its rate structure to purchase the output from small renewable resources from a member that has either wind, solar or biomass generation facilities located on their respective members systems. Due to this policy, Basin Electric would work with its member systems for this type of renewable power and would not move toward developing the resource itself.

Municipal Solid Waste

The municipal solid waste (MSW) industry includes four components: recycling, composting, landfilling and waste-to-energy via incineration. MSW is total waste excluding industrial waste, agricultural waste, and sewage sludge. As defined by the U.S. Energy Information Authority, MSW includes durable goods, non-durable goods, containers and packaging, food wastes, yard wastes, and miscellaneous inorganic wastes from residential, commercial, institutional, and industrial sources.

MSW can be directly combusted in waste-to-energy facilities to generate electricity after the separation of recyclables. Because no new fuel sources are used other than the waste that would otherwise be sent to landfills, MSW is often considered a renewable power source. Although MSW consists mainly of renewable resources such as food, paper, and wood products, it also includes nonrenewable materials derived from fossil fuels, such as tires and plastics. The U.S. EPA, the federal government and some state governments classify MSW as renewable energy source because MSW is abundant and contains significant amounts of biomass.

There are currently two main waste-to-energy facility designs; the first and most common is mass burn, in which MSW is combusted directly in much the same way as fossil fuels are used in other direct combustion technologies. Burning MSW converts water to steam to drive a turbine connected to an electricity generator.

The second is refuse-derived fuel (RDF) facilities which process the MSW prior to direct combustion. The level of pre-combustion processing varies among facilities, but generally involves shredding of the MSW and removal of metals and other bulky items. The shredded MSW is then used as fuel in the same manner as at mass burn plants.

Burning MSW can generate energy while reducing the volume of waste by up to 90 percent and 75 percent in weight. Ash disposal and the air polluting emissions from the plant combustion operations are the primary environmental impact control issues.

Waste-to-energy plants work very much like coal-fired power plants, the difference being the fuel. Waste-to-energy plants use garbage – not coal – to fire an industrial boiler. The same steps are used to make electricity in a waste-to-energy plant as in a coal-fired power plant.

1. The fuel is burned, releasing heat.
2. The heat turns water into steam.
3. The high-pressure steam turns the blades of a turbine generator to produce electricity.

Like coal plants, waste-to-energy plants produce air pollution when the fuel is burned to produce steam or electricity. Burning garbage releases the chemicals and substances found in the waste. Some chemicals can be dangerous to people, the environment, or both, if they are not properly controlled. The EPA requires waste-to-energy plants to use anti-pollution devices, including scrubbers, fabric filters, and electrostatic precipitators.

One ton of garbage has about the same heat energy as $\frac{1}{4}$ ton of coal. A ton of garbage generates about 474 kWh of electricity, enough energy to provide electricity to 16 households for one day according to the U.S. EIA³³.

³³ (Biomass Explained Waste-to-Energy (Municipal Solid Waste), 2018)

Typically, MSW power plants become economical only when landfills for MSW disposal are not available near the collection area and hauling costs become excessive.

Municipal Solid Waste power could not fulfill a need for a long-term, cost-effective generation capacity due to the rural nature of Basin Electric's service territory a solid waste-to-energy project would be very costly.

Fossil Fueled Generation

Chemically, fossil fuels consist largely of hydrocarbons, which are compounds composed of hydrogen and carbon. Some fossil fuels also contain smaller amounts of other compounds. Hydrocarbons form from ancient living organisms that were buried under layers of sediment millions of years ago. As accumulating sediment layers exerted increasing heat and pressure, the remains of the organisms gradually transformed into hydrocarbons. The most commonly used fossil fuels are coal, oil, and natural gas.

Fossil fueled energy resources evaluated in this section are simple cycle combustion turbine (SCCT), combined cycle combustion turbine (CCCT), microturbines, reciprocating internal combustion engines (RICE), and various base load coal resources, such as pulverized coal (PC), circulating fluidized bed coal (CFB), and integrated gasification combined cycle (IGCC).

Simple Cycle Combustion Turbine (SCCT)

Simple cycle is a type of combustion turbine generator (CTG) application which uses the Brayton thermodynamic cycle. In simple cycle operation, gas turbines are operated alone, without any recovery of the energy in the hot exhaust gases. Simple cycle gas turbines in the power industry require smaller capital investment than coal, nuclear, or even combined cycle natural gas plants and can be designed to generate small or large amounts of power. Also, the construction phase of project development can take as little as one year, compared to often several years for baseload power plants. Other advantages include the ability to be turned on and off within minutes, supplying power during peak demand and following quickly changing resource needs supporting the non-dispatchable renewable generation and associated instability. Since they are less efficient than combined cycle plants, they are usually used as peaking power plants, which primarily are operated during the peak summer and winter months and less than a total of 2,000 hours per year. A typical large simple cycle gas turbine may produce 25 to 150 MW of power and have 35% -40% thermal efficiency, with some reaching up to 46% efficiency. Simple cycle applications are rarely used in baseload applications because of the lower efficiencies. Figure 7-13 show a typical simple cycle unit process flow diagram.

Simple Cycle Process

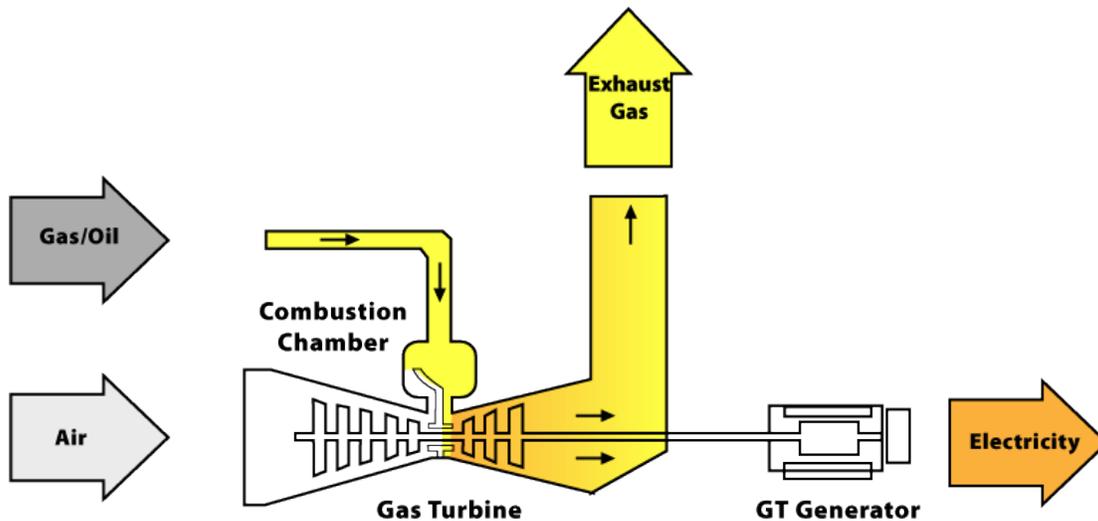


Figure 7-13 Simple Cycle Unit Process Flow Diagram

There are two types of combustion gas turbines: heavy industrial “frame” machines and aero-derivative machines. Gas turbine power plants are pre-assembled at the factory; skid or baseplate mounted, and shipped to the site along with other major components including the generator, cooling, lube oil, and electrical modules. Because of the pre-assembled modular approach, field erection hours are significantly reduced, particularly as compared to a coal-fired plant.

The capital cost component of the levelized cost of SCCT power is approximately \$750/kW to \$1,000/kW for a plant that is expected to run about 10% annual capacity factor. The total levelized cost of SCCT power is projected to be relatively high at approximately \$150/MWh to \$200/MWh depending on the price of fuel and its actual capacity factor operation. Most of the power-generation cost for SCCT is from the variable/fuel cost at approximately \$39/MWh, assuming the cost of fuel is about \$3.45/MMBTu³⁴. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Weather and demand are large factors that affect gas prices and are very unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation’s power increasingly being generated by natural gas, demand also spikes in summer, when companies fire-up peaking plants to provide more electricity for cooling needs.

Permitting of Simple Cycle units has an average timeframe of 2-3 years. This permitting timeframe is dependent on the type of machine selected and the area that you intend to construct it in. If it is on or near environmentally protected area this timeframe will increase. The construction of the Simple Cycle unit is approximately 1-1.5 years. This is dependent on availability of units, transmission and construction resources.

Simple cycle gas turbines are valid options to help meet long term power supply need if there isn’t capacity available to purchase in the market at a lower cost. Natural gas prices are currently low and are projected to remain low for the foreseeable future. With the increased oil and natural gas production in North Dakota and Montana, Natural Gas fired generation will continue to be considered in Basin’s Electrics future resource portfolios.

³⁴ (Lazard's LCOE Report v11.0, 2017)

Combined Cycle Combustion Turbine (CCCT)

Combined cycle is a term used when a power producing engine or plant employs more than one thermodynamic cycle. In a combined cycle power plant (CCPP) or combined cycle combustion turbine (CCCT) plant, a gas turbine generator generates electricity and the waste heat from the gas turbine is used to make steam to generate additional electricity via a steam turbine; this last step enhances the efficiency of electricity generation. In a thermal power plant, high-temperature heat as input to the power plant, usually from burning of fuel, is converted to electricity as one of the outputs and low-temperature heat as another output. As a rule, in order to achieve high efficiency, the temperature of the input heat should be as high as possible and the temperature of the output heat as low as possible. This is achieved by combining the Rankine (steam power system) and the Brayton (gas turbine) thermodynamic cycles. Figure 7-14 show a typical combined cycle unit process flow diagram.

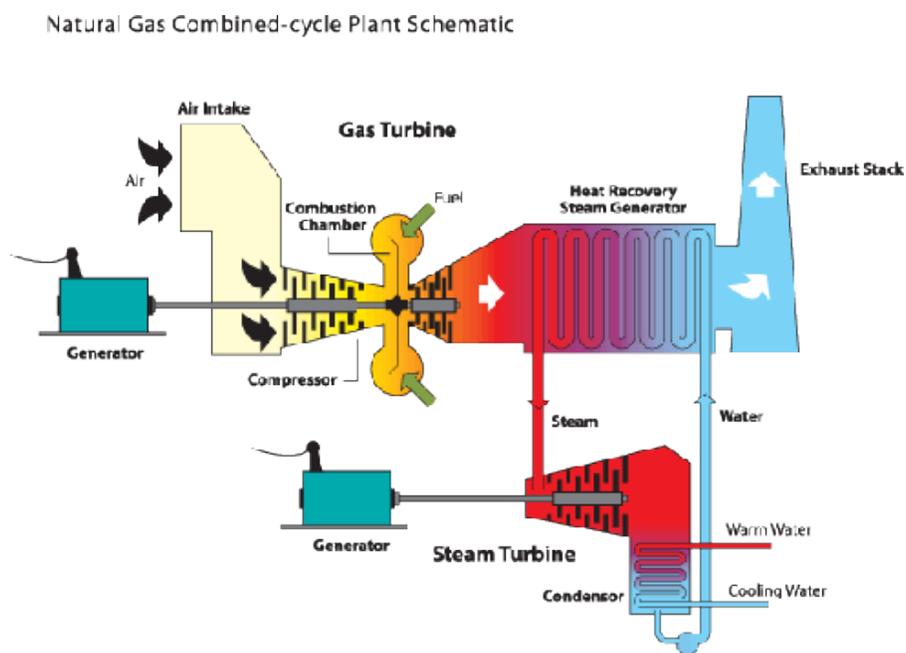


Figure 7-14 Combined Cycle Unit Process Flow Diagram

The thermal efficiency of a combined cycle power plant is normally in terms of the net power output of the plant as a percentage of the lower heating value of the fuel. In the case of generating only electricity, power plant efficiencies of up to 62% can be achieved. In the case of combined heat and power generation, the efficiency can increase to about 85% since about two-thirds of the energy in the Rankine Cycle is typically rejected to atmosphere when condensing the low temperature steam back to water. Typical combined cycle plants are powered by natural gas, although other sources of fuel can be used such as fuel oil or synthetic gas.

Combined cycle equipment is pre-engineered and factory packaged to minimize installation time and cost. All major equipment (gas turbine generator, heat recovery steam generator [HRSG], and steam turbine generator) is shipped to the field as assembled and tested modular components which are integrated during construction. CCCT plants have demonstrated high reliability and low operations and maintenance costs.

The capital cost component of the levelized cost of CCCT power is approximately \$700/kW to \$1,300/kW for a plant that runs about 40% - 80% annual capacity factor. The total levelized cost of CCCT power is projected

to be approximately \$40/MWh to \$80/MWh. If a CCCT were operated at 80% annual capacity factor, the levelized cost of power would be about \$42/MWh. Most of the power-generation cost for CCCT is from the variable/fuel cost at approximately \$25/MWh, assuming the cost of fuel is about \$3.45/MMBTu³⁵. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Weather and demand are large factors that affect gas prices and are very unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation's power increasingly being generated by natural gas, demand also spikes in summer, when companies fire-up peaking plants to provide more power for cooling needs.

Permitting of Combined Cycle units has an average timeframe of 3-4 years. This permitting timeframe is dependent on the type of machine selected and the area that you intend to construct it in. If it is on or near environmentally protected area this timeframe would increase. The construction of the Simple Cycle unit is 2-2.5 years. This is of course dependent on availability of units, transmission and construction resources.

CCCT is a valid option to help meet long term power supply needs in the more distant future. Natural gas prices are currently low and are projected to remain low for the foreseeable future. With the increased oil and natural gas production in North Dakota and Montana, natural gas fired generation will continue to be considered in Basin Electric's future resource portfolios.

Microturbines

Microturbines are small combustion turbines, approximately the size of a refrigerator, with outputs of 30-330 kW individually³⁶. They evolved from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines. These small turbines are composed of a compressor, a combustor, a turbine, an alternator, a recuperator, and a generator. Microturbines entered field-testing around 1997 and began initial commercial service in 2000. They are able to operate on a variety of fuels, including natural gas, sour gas (high sulfur, low BTU content), and liquid fuels such as gasoline, kerosene and diesel fuel/heating oil. Microturbines are classified by the physical arrangement of their component parts: single shaft or two-shaft, simple cycle or recuperated, inter-cooled and reheat. The design life of microturbines is estimated to be in the 40,000 to 80,000 hour range. While units have demonstrated reliability, they have not been in commercial service long enough to provide definitive life data.

Microturbines are ideally suited for distributed generation applications due to their small power output and space requirement, flexibility in connection methods, ability to be stacked in parallel to serve large loads, and ability to provide stable and reliable power and low emissions. Types of applications include stand-alone primary power, backup/standby power, peak shaving and primary power (grid parallel), primary power with grid as backup, resource recovery and cogeneration.

According to the U.S. Department of Energy, the total installed cost of \$2,500 - \$3,220/kW³⁷. Microturbines are still on a learning curve in terms of maintenance, as initial commercial units have seen only a few years of service so far. With the small number of units in commercial service, information is not yet sufficient to draw conclusions about reliability and availability of microturbines. The basic design and low number of moving

³⁵ (Lazard's LCOE Report v11.0, 2017)

³⁶ (U.S. DOE Microturbines, 2016)

³⁷ (U.S. DOE Microturbines, 2016)

parts hold the potential for systems of high availability; manufacturers have targeted availabilities of 98 to 99 percent.

Microturbines cannot fulfill the need for long-term, cost-effective and competitive generation for Basin Electric due to their small sizes and high installed costs; a large number of microturbines would be needed to fulfill a capacity requirement.

Reciprocating Internal Combustion Engines

Reciprocating Internal Combustion Engines (RICE) engines are common and well known technology used in automobiles and common in backup power generation. The expansion of hot gases in the combustion process drives the piston in a linear motion which is transformed to rotating movement through a crankshaft to generate electricity within an attached generator. RICE engines are characterized by the type of combustion with spark-ignited or compression-ignited systems depending on the fuel used. The compression-ignited engines are based on the Diesel Cycle whereas the spark-ignited engines are based on the Otto Cycle and require an ignition source. Natural gas RICE engines are becoming more common in utility scale electrical power generation.

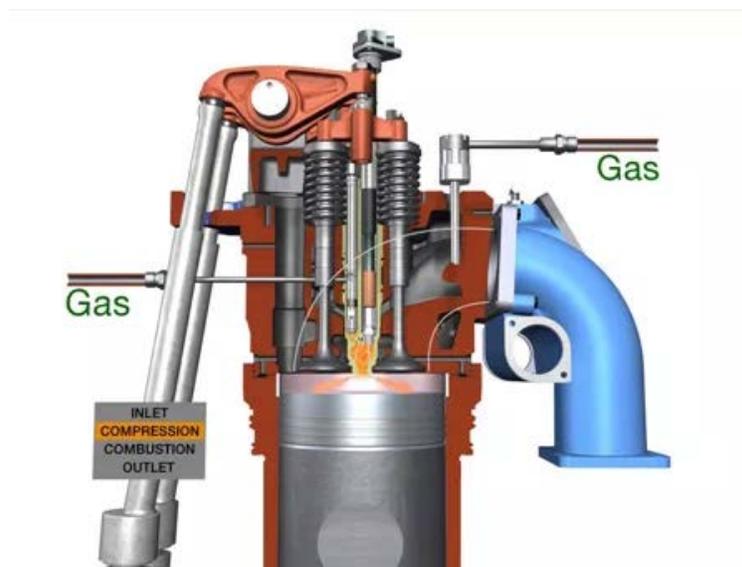


Figure 7-15 Spark Ignited Combustion Engine³⁸

Capital costs for natural gas fueled RICE engine is estimated at \$650/kW to \$1,100/kW according to Lazard's 2017 Levelized Cost of Energy Analysis report³⁹. The associated fixed O&M is estimated at \$15/kW-yr to \$20/kW-yr and variable O&M at \$10/MWh to \$15/MWh.

Natural gas fueled RICE engines have similar permitting, construction timelines, and quick response advantages as simple cycle combustion turbines. RICE engine efficiency using natural gas is estimated at

³⁸ (Wartsila, n.d.)

³⁹ (Lazard's LCOE Report v11.0, 2017)

43.7% on a higher heating value basis resulting in an electric heat rate around 8,000 BTU/kWh⁴⁰ giving RICE engines a leg up on efficiency in comparison.

Basin Electric has recently added RICE units to the generating fleet and will continue to consider this technology for electrical generation needs.

Coal Facility

Three types of coal facilities are discussed below, they include pulverized coal (PC), circulating fluidized bed (CFB) and integrated gasification combined cycle (IGCC).

Pulverized Coal

Modern pulverized coal (PC) plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Coal is most often delivered by unit train to the site, although barges or trucks are also used. Many plants are situated adjacent to the coal source where coal delivery can be by conveyor. The source of coal and coal characteristics can have a significant effect on the plant design in terms of coal-handling facilities and types of pollution control equipment required. Coal can have various characteristics with varying heating values, sulfur content, and ash constituents.

Regardless of the source, the plant coal-handling system unloads the coal, stacks out the coal, reclaims the coal required, and crushes the coal for storage in silos. Then the coal is fed from the silos to the pulverizers and blown into the steam generator. The steam generator mixes the pulverized coal with air, which is combusted, and in the process produces heat to generate steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity. This process is shown Figure 7-16 below.

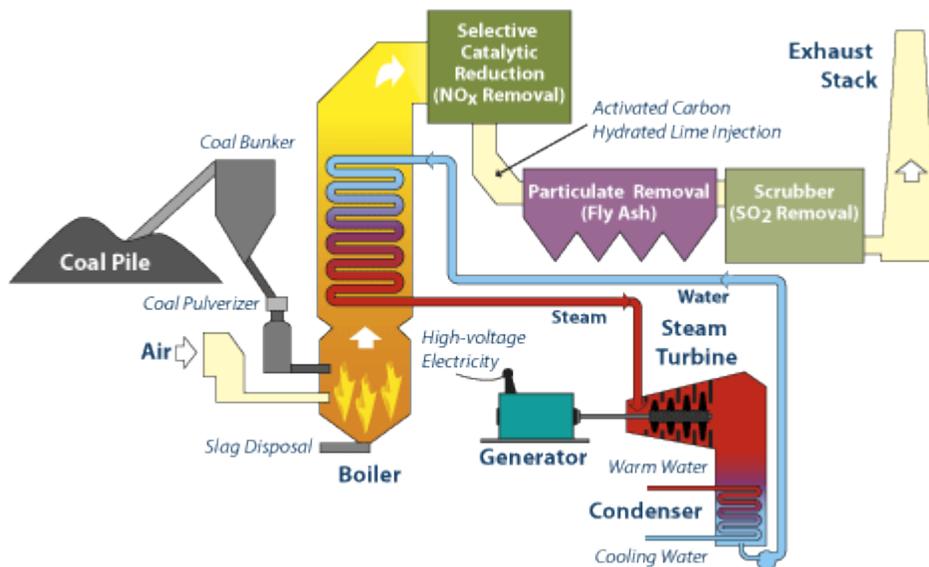


Figure 7-16 Pulverized Coal Unit Process Flow Diagram

⁴⁰ (Lazard's LCOE Report v11.0, 2017)

Typically, a PC unit would be utilized in baseload operation to optimize the cost of the facility. Coal burning generating stations tend to be higher in capital cost and lower in operating cost and have a longer life span than a typical combustion turbine facility, thereby reducing the overall cost of generation.

Environmental impacts associated with PC resources include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

The permitting and environmental study requirements to install a new PC coal fired unit would take approximately 5 years and construction time after permitting would require 4 years. The permitting and environmental portions of this process would require the latest technologies in carbon capture. Without the carbon capture processes these potential new facilities will not be granted required air quality permitting or environmental state and federal regulations.

Basin Electric currently owns and operates several PC resources within its system. These facilities have been upgrading their emission control equipment over the years. See Recent Projects in Chapter 4) The Planning Environment for details of the emission control retrofits of the Basin Electric coal fleet.

Circulating Fluidized Bed

Circulating fluidized bed (CFB) technology utilizes the fluidized bed principle in which crushed fuel and limestone are injected into the furnace or combustor. The particles are suspended in a stream of upwardly flowing air (60 to 70 percent of total air) which enters the bottom of the furnace through air distribution nozzles. The balance of combustion air is admitted above the bottom of the furnace as secondary air. While combustion takes place at 840°C to 900°C (1,550°F to 1,650°F), the fine particles exit the furnace with flue gas. The particles are then collected by the solids separators and circulated back into the furnace. This combustion process is called circulating fluidized bed (CFB). The particles' circulation provides efficient heat transfer to the furnace walls and longer residence time for carbon and limestone utilization.

The CFB fuel delivery system is similar to the PC unit, but somewhat simplified to produce a coarser material. Figure 7-17 shows a typical circulating fluidized bed unit process flow diagram. CFBs are designed for the particular coal to be used. The method is principally of value for low grade, high-ash coals that are difficult to pulverize and that may have variable combustion characteristics. It is also suitable for co-firing with low-grade fuels, including some waste materials.

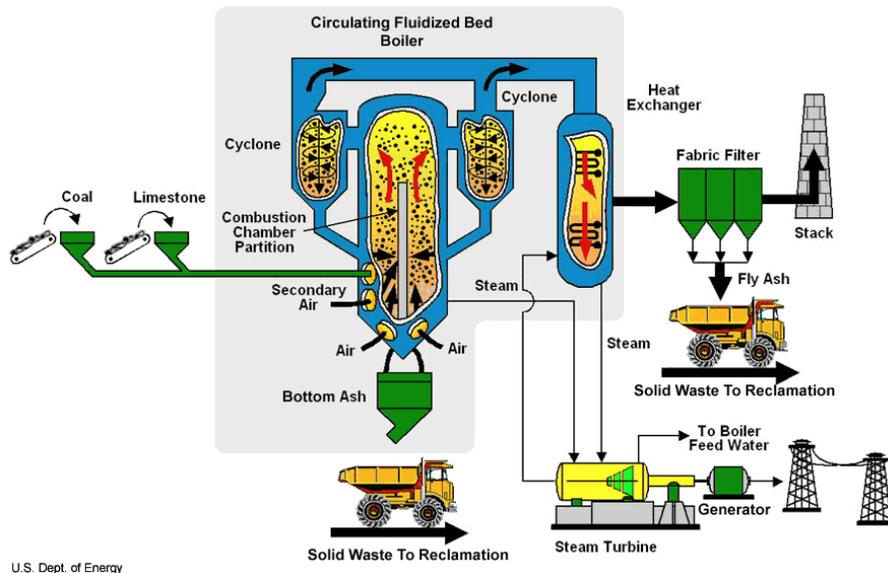


Figure 7-17 Circulating Fluidized Bed Unit Process Flow Diagram

Typically, a CFB unit would be utilized in baseload operation to optimize the cost of the facility. Coal burning generating stations tend to be higher in capital cost and lower in operating cost and have a longer life span than a typical combustion turbine facility, thereby reducing the overall cost of generation.

Environmental impacts associated with CFB resources include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

The permitting and environmental study requirements to install a new CFB coal fired unit would take approximately 5 years and construction time after permitting would require 4 years. The permitting and environmental portions of this process would require the latest technologies in carbon capture. Without the carbon capture processes these potential new facilities will not be granted required air quality permitting or environmental state and federal regulations.

Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) merges gasification with gas cleaning, synthesis gas conversion, and turbine power technologies. IGCC uses a gasifier to convert a carbon-based feedstock (i.e. coal) into synthesis gas, a mixture of carbon monoxide (CO) and hydrogen (H₂). The synthesis gas is cleaned of particulates, sulfur, and other contaminants and is then combusted in a high-efficiency Brayton cycle gas turbine/generator. Heat from the turbine exhaust gas is extracted to produce steam to drive a Rankine cycle steam turbine/generator. The specifics of a plant design are influenced by the gasification process, degree of heat recovery, and methods to clean up the gas. This combination of power-generating cycles is known as a combined cycle. Figure 7-18 show the typical process flow diagram for an IGCC unit.

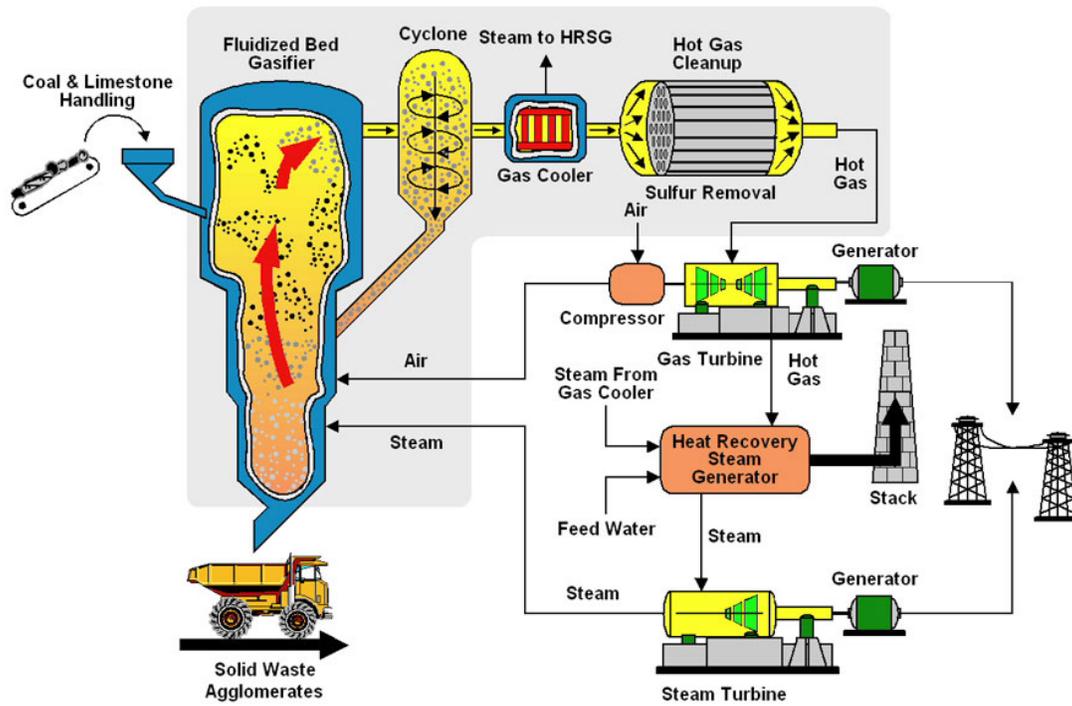


Figure 7-18 Integrated Gasification Combined Cycle Process Flow Diagram

The gasifier has the flexibility to handle a variety of feedstocks. In addition to coal, possible feedstocks include petroleum coke, refinery liquids, biomass, municipal solid waste, tires, plastics, hazardous wastes and chemicals, and sludge. The main incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies (40% or greater) than conventional power plants (35%) and may be able to match the environmental performance of gas-fired plants.

IGCC is capital intensive, it needs economies of scale and fuel cost advantages to be an attractive investment option.

The permitting and environmental study requirements to install a new IGCC coal fired unit would take approximately 4.5 years and construction time after permitting would require 4 years. The permitting and environmental portions of this process would require the latest technologies in carbon capture. Without the carbon capture processes these potential new facilities will not be granted required air quality permitting or environmental state and federal regulations.

Summary of Coal Facilities

Before delving into the cost of the three coal facilities, a thorough technology assessment would need to be performed. However, for this IRP a generic coal facility without CO₂ capture, compression, and sequestration was assumed which was estimated to have a capital cost of \$3,000/kW to \$8,400/kW, fixed O&M of \$40/kW-yr to \$80/kW-yr, variable O&M of \$2/MWh to \$5/MWh, and assumed \$1.47/MMBTu. This results in a total levelized cost of energy in the \$60/MWh to \$143/MWh range assuming a 40 year lifespan averaging a 93% annual capacity factor⁴¹.

While coal facilities are not excluded from the analysis of Basin Electric's future power supply needs, they are likely not a viable option with the low natural gas prices we see today and a world that is heading towards more and more regulations on emissions.

⁴¹ (Lazard's LCOE Report v11.0, 2017)

Nuclear Power

Nuclear power is a type of technology involving the controlled use of nuclear reactions to release energy for work including propulsion, heat, and the generation of electricity. Nuclear energy is produced by a controlled nuclear chain reaction and creates heat, which is used to boil water, produce steam, and drive a steam turbine to generate electricity.

As of 2016, the International Atomic Energy Agency (IAEA) reported there are 449 nuclear power reactors in operation in the world, with 392 GW of capacity⁴². These reactors provided 11% of the world's total electricity. At the end of 2016, there were 61 reactors under construction, mostly in. The EIA reported that as of December 2017, there were 99 nuclear power reactors operating in the United States. These reactors provide about 20% of the total annual U.S. electricity with a capacity of 100 GW and 800,000 GWh of energy being produced annually⁴³.

Conventional thermal power plants all have a fuel source to provide heat (i.e. coal, oil, and gas). For a nuclear power plant, this heat is provided by nuclear fission inside the nuclear reactor. When a relatively large fissile atomic nucleus is struck by a neutron it forms two or more, smaller nuclei as fission products, releasing energy and neutrons in a process called nuclear fission. When this nuclear chain reaction is controlled, the energy released can be used to heat water, produce steam and drive a turbine to generate electricity. Figure 7-19 shows the process flow diagram of a nuclear power plant.

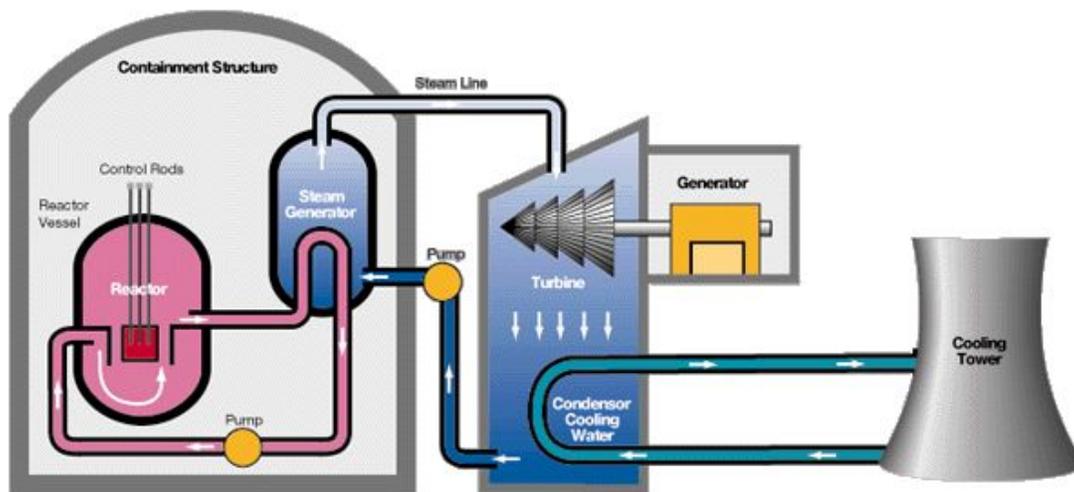


Figure 7-19 Nuclear Power Plant Process Flow Diagram

A nuclear reactor is only part of the life-cycle for nuclear power. The process starts with mining in which the uranium ore is extracted, usually converted in a stable and compact form such as yellowcake, and then transported to a processing facility. Here, the yellowcake is converted to uranium hexafluoride, which is then enriched using various techniques. At this point, the enriched uranium, containing more than the natural 0.7 percent U-235 (Uranium -235), is used to make rods of the proper composition and geometry for the particular reactor that the fuel is destined for. The fuel rods will spend 1.5 to 3 years inside the reactor, generally until about 3 percent of their uranium has been fissioned, then the rods will be moved to a spent fuel pool where the short lived isotopes generated by fission can decay away. After about 1 year in a cooling

⁴² (IAEA Nuclear Fact Sheets, 2016)

⁴³ (EIA Electricity Data, 2017)

pond, the spent fuel is radioactively cool enough to handle. The US NRC has two acceptable storage methods; it can be kept in the spent fuel cooling pond at the reactor site or moved to dry storage casks. Dry storage casks are steel cylinders that are either welded or bolted closed. The steel cylinder provides a leak-tight confinement of the spent fuel. Each cylinder is surrounded by additional steel, concrete, or other material to provide radiation shielding to workers and members of the public. Some of the cask designs can be used for both storage and transportation.

Nuclear power plants are generally (although not always) considered “hard” targets. The reactor is typically protected by about four feet of steel-reinforced concrete with a thick steel liner, and the reactor vessel is made of steel about 6 inches thick. Steel-reinforced concrete containment structures are designed to withstand the impact of many natural disasters, including hurricanes, tornadoes, earthquakes and floods, as well as airborne objects with a substantial force. In the U.S., plants are surrounded by a double row of tall fences which are electronically monitored and the plant grounds are patrolled by a sizeable force of armed guards. The NRC holds nuclear power plants to the highest security standards of any American industry. Since 2001, the agency has elevated nuclear plant security requirements numerous times by issuing orders and other formal requirements.

Nuclear generation does not directly produce sulfur dioxide, nitrogen oxides, carbon dioxide, mercury or other pollutants associated with the combustion of fossil fuels. With increased interest in air pollution and global warming, nuclear power generation would be an excellent source of electric power generation since nuclear generation does not contribute to the causes of air pollution and global warming via greenhouse gas emissions.

Nuclear generation is considered baseload generation, with the existing U.S. fleet of nuclear power plants operating at approximately 90% capacity factor for the last number of years. Nuclear fuel costs are not volatile and account for only a small portion of overall production costs, thus providing excellent overall price stability.

There are many issues to overcome in order to develop new nuclear generation. Some of the issues pertain to cost, standardization, financing, plant licensing and construction. The cost of new nuclear generation needs to be competitive with other generation in order to facilitate new nuclear generation. Financing provides an issue due to the hefty price tag associated with new generation and scrutiny due to that price. Construction of new nuclear power plants is likely to face bottlenecks due to the availability of key components and the workforce of craft workers and construction managers. Increased demand of the key components will eventually lead to greater manufacturing capacity, but there will be a delay in that greater manufacturing capacity. One of the largest issues facing new nuclear plants is the public perception of nuclear power. The March 2011 earthquake and tsunami that devastated northeast Japan led to a severe accident at the Fukushima Daiichi nuclear energy facility. This incident significantly hurt the nuclear power industry and led to a complete inspection of all US domestic nuclear power plants.

The new plant licensing process that has three components: approval of standard reactor designs, early site permits and combined construction and operating licenses.

The U.S. Nuclear Regulatory Commission has certified several reactor designs as meeting all safety requirements, and the agency expects to certify two more designs in the near term. These designs can be found on the Nuclear Energy Institute website, under “New Nuclear Energy Facilities”.

The U.S. Nuclear Regulatory Commission (NRC) voted in February 2012 to grant a combined construction and operating license for two reactors at Southern Co. subsidiary Georgia Power’s Plant Vogtle, near Waynesboro. It is the first combined license ever approved for a U.S. nuclear energy facility, which were the

nation's first new reactors to receive construction approval in 30 years. On March 30, 2012, the NRC issued combined construction and operating licenses to South Carolina Electric & Gas Company for two reactors near Jenkinsville, South Carolina. However, construction on these units ceased in 2017.

Tennessee Valley Authority's Watts Bar Unit 2 became the first new U.S. reactor to come online since 1996 when it achieved commercial operation of the 1,150 MW unit in October 2016. Vogtle Units 3 and 4 are currently under construction and scheduled to be operational in 2019 and 2020. As of September 2017, there were about 18 applications for new reactors at the NRC. However, the U.S. EIA projects an overall decrease in the total nuclear electric generation capacity every year from 2017 through 2050.⁴⁴

Due to the many issues that the utility industry will face with new nuclear generation, Basin Electric believes it would be quite some time before a new nuclear power plant could be built to help meet the growing need of Basin Electric. However, due to the advantage nuclear generation would bring to the growing air quality restrictions, Basin Electric will continue to evaluate the options but for the timeframe of this IRP will look to other technologies to meet its growing needs

Repowering/Uprating of Existing Generating Units

Periodic review is done at existing facilities to determine the economic viability of repowering/uprating of existing generating units. However, at this time Basin Electric does not have any plans to repower or uprate any of their generating units.

⁴⁴ (EIA Electricity Data, 2017)

Summary of Supply Side Resource Alternatives

A summary of the projected costs for alternative generation within Basin Electric eastern system, where cost information is known, is shown in Table 7-2 through Table 7-4 separated into three different technology-type categories (clean/renewable, dispatchable technologies that can be constructed in 2 years or less, and dispatchable technologies with construction times beyond 2 years). The power-generation technologies presented with their respective costs are on-shore wind, utility scale solar photovoltaic, geothermal, biomass, reciprocating internal combustion engines (RICE) with both diesel and natural gas as fuel sources, microturbines, simple cycle combustion turbines, combined cycle combustion turbines, nuclear facilities, coal facilities, and integrated gasification combined cycle facilities.

| Type of Power Plant | On-Shore Wind | Utility Scale Solar PV | Geothermal | Biomass |
|---|---------------|------------------------|-------------|-------------|
| Capital Cost (\$/kW) | 1,200-1,650 | 1,100-1,375 | 4,000-6,400 | 1,700-4,000 |
| Fixed O&M (\$/kW-yr) | 30-40 | 9-12 | 0 | 50 |
| Variable O&M (\$/MWh) | 0 | 0 | 30-40 | 10 |
| Average Capacity Factor (%) | 38-55 | 21-30 | 85-90 | 80-85 |
| Fuel Cost (\$/MWh) | 0 | 0 | 0 | 14.50-29 |
| Construction Time (Months) | 12 | 9 | 36 | 36 |
| Levelized Cost of Energy (\$/MWh) ⁴⁵ | 30-60 | 46-53 | 77-117 | 55-114 |

Table 7-2 Cost of New Resource - Clean/Renewable Technologies⁴⁶

| Type of Power Plant | RICE - Diesel | RICE - Gas | Microturbine | Simple Cycle CT |
|---|---------------|------------|--------------|-----------------|
| Capital Cost (\$/kW) | 500-800 | 650-1,100 | 1,500-2,700 | 750-1,000 |
| Fixed O&M (\$/kW-yr) | 10 | 15-20 | 5-9.12 | 5-20 |
| Variable O&M (\$/MWh) | 10 | 10-15 | 5-10 | 4.70-10 |
| Average Capacity Factor (%) | 10-95 | 30-95 | 95 | 10 |
| Fuel Cost (\$/MWh) | 173-182 | 44-55 | 31-41 | 28-34 |
| Construction Time (Months) | 3 | 3 | 3 | 12-18 |
| Levelized Cost of Energy (\$/MWh) ⁴⁷ | 197-281 | 68-106 | 59-89 | 156-210 |

Table 7-3 Cost of New Resource - Near Term Dispatchable Technologies⁴⁸

⁴⁵ This version of Lazard estimates provides the LCOE on an unsubsidized basis, so they do not include the benefits that could be seen from the U.S. Federal Production Tax Credit (PTC) or Investment Tax Credit (ITC)

⁴⁶ (Lazard's LCOE Report v11.0, 2017)

⁴⁷ This version of Lazard estimates provides the LCOE on an unsubsidized basis, so they do not include the benefits that could be seen from the U.S. Federal Production Tax Credit (PTC) or Investment Tax Credit (ITC)

⁴⁸ (Lazard's LCOE Report v11.0, 2017)

| Type of Power Plant | Combined Cycle CT | Nuclear Facility | Coal Facility | Integrated Gasification CC |
|---|-------------------|------------------|---------------|----------------------------|
| Capital Cost (\$/kW) | 700-1,300 | 6,500-11,800 | 3,000-8,400 | 4,175-16,200 |
| Fixed O&M (\$/kW-yr) | 5.50-6.20 | 135 | 40-80 | 73 |
| Variable O&M (\$/MWh) | 2-3.50 | 0.75 | 2-5 | 8.5 |
| Average Capacity Factor (%) | 40-80 | 90 | 93 | 75 |
| Fuel Cost (\$/MWh) | 21-24 | 9 | 13-18 | 7.61 |
| Construction Time (Months) | 24 | 69 | 60-66 | 57-63 |
| Levelized Cost of Energy (\$/MWh) ⁴⁹ | 42-78 | 112-183 | 60-143 | 96-231 |

Table 7-4 Cost of New Resource - Long Term Dispatchable Technologies⁵⁰

In the event that Basin Electric was not able to go out and secure bilateral contracts with other neighboring utilities, the generation types capable of meeting Basin Electric's near term capacity needs would be those that can be constructed in the next few years with the ability to be dispatched when needed. These technologies include RICEs, SCCTs, and microturbines although microturbines are generally very small in size and therefore a large quantity would be needed as well as being fairly costly for baseload generation.

RICEs and SCCTs are already a part of Basin Electric's resource portfolio and perform very well, so along with being able to meet Basin Electric's near term power supply needs, they are also a viable option for meeting at least a portion of Basin Electric's needs in the more distant future. Other generation types that are capable of meeting Basin Electric's needs in the more distant future (5-10 years) include CCCTs, coal and nuclear facilities, and IGCCs. While all of these technologies are constantly being monitored, it is not likely that new coal, nuclear, or IGCC facilities will be added to Basin Electric's portfolio any time soon due to their higher costs as well as an uncertain future but one that seems to be heading towards more constraints on carbon emissions.

Currently Basin Electric's needs can likely be met via bilateral contracts with neighboring utilities in the near term and then likely building peaking and intermediate natural gas facilities such as SCCTs, RICEs, and CCCTs sometime in the future probably around 2026 to 2028 at the earliest. While these peaking and intermediate resources are good for meeting Basin Electric's capacity needs, they may not make up for all of Basin Electric's energy needs but provide for a backstop to the market or other energy alternatives. While some exposure to the energy markets is acceptable, wind resources make for a good way to reduce Basin Electric's energy exposure due to being a relatively cheap resource and having moderately high average annual capacity factors in our footprint. Basin Electric has already constructed and secured power purchase agreements for more than 1,300 MW of wind currently online with contracts for another 400MW to be online by the end of 2020 and is also considering securing even more PPAs for wind generation to further reduce Basin Electric's energy exposure to the market.

⁴⁹ This version of Lazard estimates provides the LCOE on an unsubsidized basis, so they do not include the benefits that could be seen from the U.S. Federal Production Tax Credit (PTC) or Investment Tax Credit (ITC)

⁵⁰ (Lazard's LCOE Report v11.0, 2017)

Energy Storage

Electrical energy is not easily stored like the chemical energy in fossil fuels (coal, oil, natural gas, etc.). Energy storage is increasingly important as renewables become a larger portion of the total generation mix. Renewables can sometimes be dispatched to reduce generation but can never be dispatched to produce more energy unless they are not being operated at their full potential. If significant energy storage was available, it would be possible to sink the “must take” energy from renewables like wind and solar to a storage device and recover the energy later when it is needed. Thus, better balancing the generation with the load.

It’s important to remember that energy storage devices result in the consumption of energy as a cost of energy conversion. The capital costs associated with storage can only be justified with avoided costs or revenue generation based on ancillary services and the difference in market on-peak and off-peak energy prices.

Pumped Hydro

Approximately 95% of global energy storage is in the form of pumped hydro⁵¹. Pumped hydro has been around for decades and is a proven energy storage technology. Its simple concept consists of using electricity to pump water uphill to a reservoir converting the electric energy to potential energy. When electrical energy is desired, the water is allowed to flow back to its original elevation and the kinetic energy from gravity is converted into electric energy through turbine generator sets.

All energy storage devices experience losses and the amount of electrical energy recovered is less than what was put into storage. In the case of pumped hydro, the energy storage can be from 70% to 80% efficient meaning that for every 1 megawatt hour of energy put into the storage about 0.7 to 0.8 megawatt hours are able to be recovered.

Pumped hydro holds advantages in that it is simple and its ability to store energy (megawatt hours) is constrained by the size of the higher elevation reservoir. Depending upon the size of the upper reservoir, a pumped storage facility could provide energy throughout the typical on-peak hours of the day. The rate at which electrical energy can be stored or produced (megawatts) is constrained by the size of the pumps/turbines installed. Like hydroelectric plants, pumped hydro storage facilities can respond quickly to system needs for frequency regulation, energy regulation up or down, and spinning reserves in the event another generation unit trips offline.

Disadvantages of pumped hydro include locational constraints, cost, and permitting. The elevated reservoir must be located near a large, existing body of water and should offer the greatest elevation change reasonably possible since the elevation difference provides the energy storage driving force. If a manmade lake is required to store the water, it may consume hundreds or thousands of acres of land depending on the topography of the land. Proposing to flood large amounts of land would likely be challenging to permit along with the construction from the upper to lower reservoir. Furthermore, the ability to consume and discharge large volumes of water from an existing lake or river ecosystem would likely change the elevation of the water level dramatically. Finally, the cost associated with the capital expenditures could be extensive with the magnitude of real estate and construction required.

⁵¹ (U.S. DOE Pumped Storage Hydro, n.d.)

In the past, Basin Electric has considered the Gregory County Pumped Storage project. The topography is attractive for a pumped hydro storage facility in Gregory County, SD. However, the capital cost to build the 1,200 MW facility was expected to be \$1.1 billion in the 2004 feasibility study conducted by Black & Veatch for the South Dakota Department of Environmental and Natural Resources and more than \$2.2 billion in the 2013 feasibility study conducted by Schulte Associates⁵². Basin Electric's involvement ceased since the leveled bus bar cost was estimated to be too high.

The site specific challenges and costs associated with pumped hydro energy storage compared to other alternatives make it difficult to consider as a viable alternative to fulfill Basin Electric's needs.

Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) is similar to pumped hydro except pressure difference is the driving force rather than elevation difference. This type of energy storage uses electricity to drive an air compressor which forces air into a vessel or naturally occurring geological formation underground. When electrical energy is desired, the compressed air is released to spin a turbine generator set. The compressed air can be used in a combustion turbine to drive a generator without the compressor section of a conventional combustion turbine generator.

Round trip efficiency of CAES is estimated at 50% to 60% including transformers and transmission line losses. Again, this translates to 0.5 to 0.6 MWhs of energy available for reuse for every 1 MWh put into the storage system due to losses in the energy conversion.

The CAES system shares the potential advantage to hold a significant amount of energy like pumped hydro. However, the CAES systems will have a much smaller above ground footprint than pumped storage.

Disadvantages of this energy storage method include lower estimated efficiency and anticipated public resistance to pressurized air storage underground. Efficiency is reduced compared to pumped hydro since the ambient air rises in temperature as it is compressed, and the heat loss translates to energy loss.

There are two known CAES projects operating around the world today. One is in Alabama, and one is in Germany. For these reasons, CAES is considered too early in the technology development stage and Basin Electric will continue to evaluate the options into the future, but for the timeframe of this IRP will look to other technologies to meet its growing needs.

⁵² (SD DENR Gregory County Pumped Storage, 2004)

Battery Storage

There are two main types of batteries used for energy storage, the rechargeable battery and the flow battery which is an emerging technology. The batteries we are most familiar with in our vehicles, cell phones, and tools are rechargeable batteries commonly using lead acid, nickel cadmium (NiCd), and lithium ion (Li-ion) materials to store electrical energy in a chemical form. Flow batteries operate in a similar manner to rechargeable batteries except instead of flooded cells, in a flow battery there are pumps and electrolyte storage tanks used to transfer electricity into chemical energy within the electrolyte.

Round trip efficiency for rechargeable batteries ranges from 80% - 90%. At the end of 2017, 708 MW of capacity representing 867 MWh of large scale energy capacity battery storage was in operation within the U.S. according to the EIA. Over 80% of this capacity utilizes lithium-ion chemistries.⁵³ Most of these installations, nearly 40%, are found in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) in response to the frequency regulation market created in 2012. The California Independent System Operator (CAISO) accounted for 18% of existing large scale battery storage in 2017 as reported in the EIA's U.S. Battery Storage Market Trends.

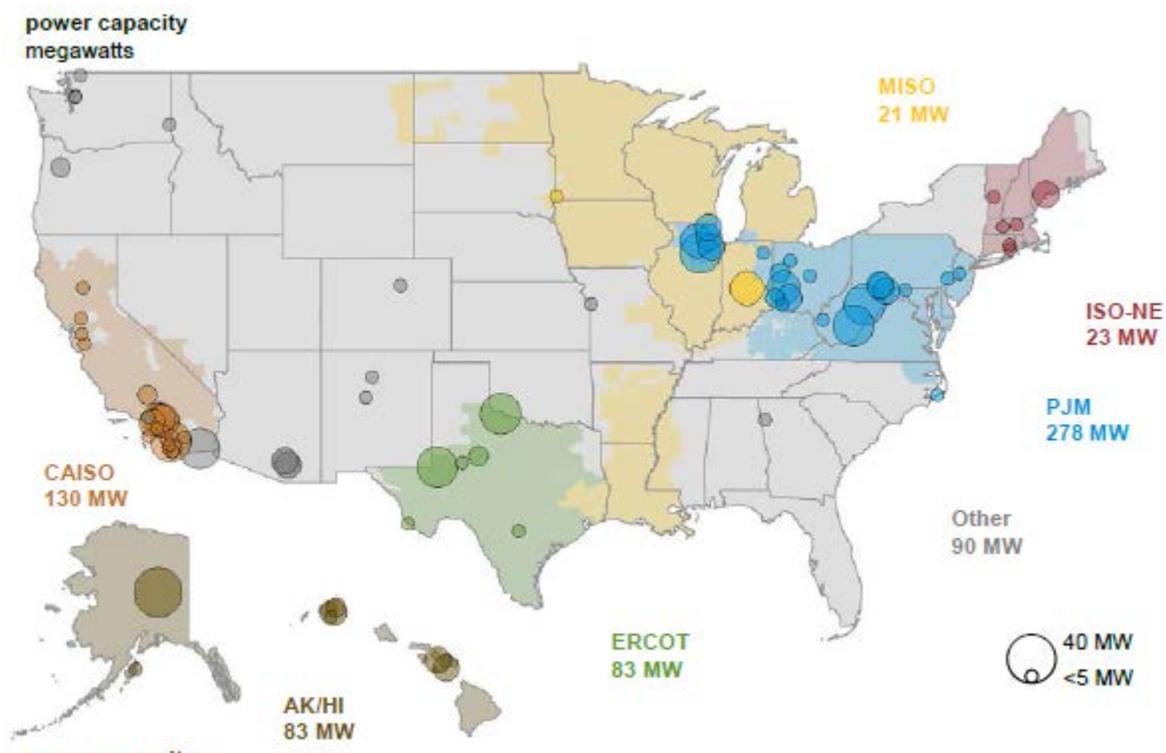


Figure 7-20 Large Scale Battery Storage Installations (2017)

Li-ion batteries provide efficient power and energy density and there is a rapidly expanding manufacturing base which should continue to drive cost reductions. However, Li-ion batteries are cycle life limited and have safety related issues associated with overheating.⁵⁴

⁵³ (EIA US Battery Storage, 2018)

⁵⁴ (Lazard's LCOE Report v11.0, 2017)

Lazard's estimates for Levelized Cost of Electricity (LCOE) of Li-ion batteries as a peaking resource replacement range from \$268/MWh to \$347/MWh in their Levelized Cost of Storage Analysis. At this time, there seem to be only niche applications where energy storage can be the best alternative when other cost savings can be realized such as battery storage in lieu of substation or transmission upgrades. For these reasons, Basin Electric will continue to follow the progress of technology development around battery storage and the potential changes within various markets which effect the revenue potential of a battery storage project.

Demand Side Resources

Demand Side Management (DSM) is the process of managing the consumption of energy, generally to optimize available and planned generation resources. According to the Department of Energy, DSM refers to "actions taken on the customer's side of the meter to change the amount or timing of energy consumption. Utility DSM programs offer a variety of measures that can reduce energy consumption and consumer energy expenses. Electricity DSM strategies have the goal of maximizing end-use efficiency to avoid or postpone the construction of new generating plants."

DSM programs aim to achieve three broad objectives; energy conservation, energy efficiency and load management. Energy conservation can reduce the overall consumption of electricity by reducing the need for heating, lighting, cooling, cooking energy and other functions. Energy efficiency can encourage consumers to use energy more efficiently, and thus get more out of each unit of electricity produced. Load management allows generation companies to better manage the timing of their consumers' energy use, and thus help reduce the large discrepancy between on-peak and off-peak demand.

Basin Electric and its members are engaged in a variety of conservation and energy efficiency programs. The programs and activities were developed to promote, support and market dual heat, water heaters, heat pumps, air conditioning, storage heating, grain drying, irrigation, photovoltaic, energy audits, and numerous other programs. A number of Basin Electric's members have developed programs and these programs vary depending on the cooperative, some elect to utilize rebates, others energy resource conservation (ERC) loans, others rates, some all three and some may elect not to adopt any of the programs.

Energy conservation and efficiency programs are capable of lessening the impact of electrical demand and reducing the capacity of future additional generation facilities. Energy conservation is behavior based while energy efficiency is technology based. Therefore, energy conservation and efficiency programs could be considered in parallel of adding additional generating capability to meet the Basin Electric projected demand.

Approximately half of the Basin Electric members are utilizing load management to manage their power purchases from Basin Electric. This was further discussed in Chapter 6) Load and Resource Balance under the subsection. Basin Electric has implemented a system-wide load management program on its eastern system which enables Basin Electric to target large loads and/or generation that are not included in the members' load management programs to be used during Basin Electric's seasonal peak periods. Basin Electric has approximately 8 MW of load management available at this time and is continuing to look to improve this.

Basin Electric also continues to work with its membership on ways to help their member electric marketing programs. Our Demand Period Waiver program gives the membership access to an electric rate, for shoulder and off-peak periods, without an associated demand assessment. This allows the membership to reduce the number of hours of consumer load management which hopefully will allow the membership the ability to offer additional load management control alternatives to end consumers. This in turn should allow for a reduction in the amount of on-peak resource additions needed by Basin Electric.

Transmission Resources

As discussed in Chapter 5) Transmission Planning under the section, Basin Electric currently has access to several DC ties that bridge the connections of the national electric system with the values and directions of the rights specified in Table 5-2 and again in Table 7-5 below.

Basin Electric is currently in the process of evaluating options to secure additional rights on DC ties to transfer surplus power supply from our system in the Rocky Mountain Reserve Sharing Group (RMRG) region in the western interconnection into the Southwest Power Pool (SPP) region in the eastern interconnection. Basin Electric already has rights to transfer up to 240 MW from the RMRG region to SPP across the Rapid City and Stegall DC ties.

| DC Tie | Capacity (MW) | BEPC % Ownership | BEPC Rights (MW) |
|-------------------|---------------|----------------------|----------------------|
| Miles City DC Tie | 200 | 40% | 183 (east→west only) |
| Stegall DC Tie | 110 | 0% (Tri-State Owned) | 110 (bi-directional) |
| Rapid City DC Tie | 200 | 65% | 130 (bi-directional) |

Table 7-5 DC Tie Capacity, Ownership, and Rights

Market Purchases

Purchased Power/Request for Proposals

Basin Electric developed and issued a Request for Proposals (RFP) in early 2018 for power supply proposals in SPP, MISO LRZ 1, and NWPP (NorthWestern Energy or WAUW). The long-term proposals were used to evaluate against Basin Electric's self-build options. The short-term proposals could be utilized to meet some of Basin Electric's need in the next couple of years. Basin Electric received 3,445 MW of power supply bids. Basin Electric evaluated the short- and long-term proposals and shortlisted the total number of qualifying bids to 9 totaling 790 MW. In addition, four wind project proposals were held over from the 2017 RFP for further evaluation as long term power supply options, totaling 600 MW.

8) Regional Power Supply Analysis

Introduction

According to the Energy Information Administration, the U.S. net electricity generation in 2017 was 4,014,804 thousand megawatt-hours. Energy sources and percent share of total for electricity generation are provided below in Table 8-1.

| Fuel | Thousand MWh | % of Total |
|----------------------------|--------------|------------|
| Natural Gas | 1,272,864 | 31.7% |
| Coal | 1,207,901 | 30.1% |
| Nuclear | 804,950 | 20.1% |
| Conventional hydroelectric | 300,045 | 7.5% |
| Wind | 254,254 | 6.3% |
| Biomass | 64,057 | 1.6% |
| Utility-scale solar | 52,958 | 1.3% |
| Other | 57,775 | 1.4% |
| Total | 4,014,804 | |

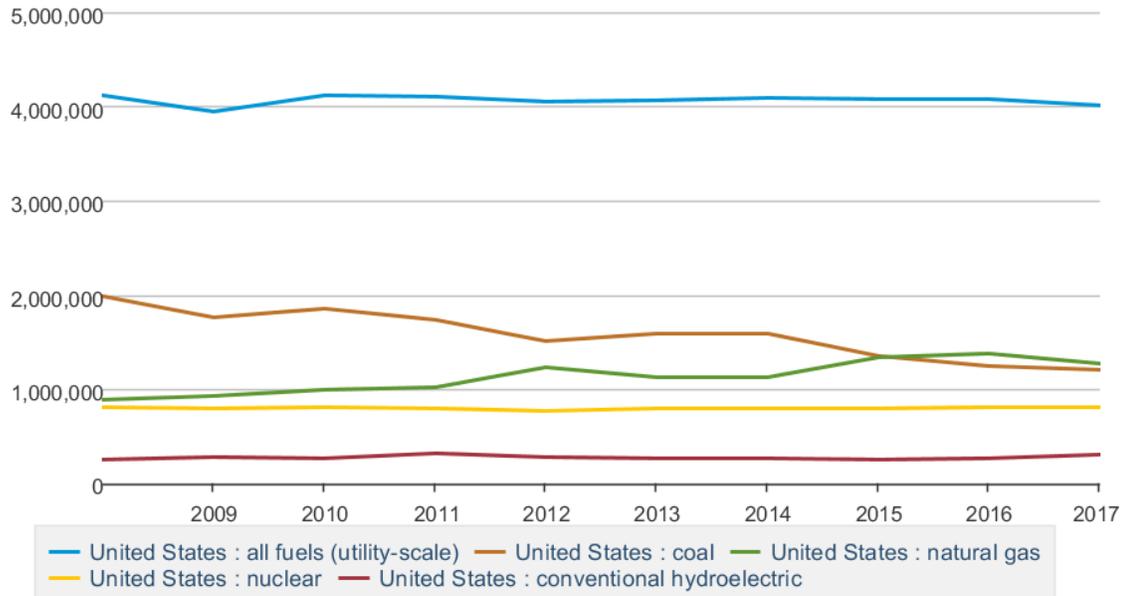
Table 8-1 U.S. Net Generation by source, 2017⁵⁵

The following figures display the changing generation resource mix in the U.S. over the last ten years. Natural gas has become the predominant new resource for new dispatchable generation, and has surpassed coal in terms of annual megawatt hours. Wind and solar have emerged as substantial generation contributors over this time period. Traditional hydroelectric and nuclear power have been stable, while coal fired generation has declined.

⁵⁵ (EIA Electricity Data, 2017)

Net generation for all sectors, annual

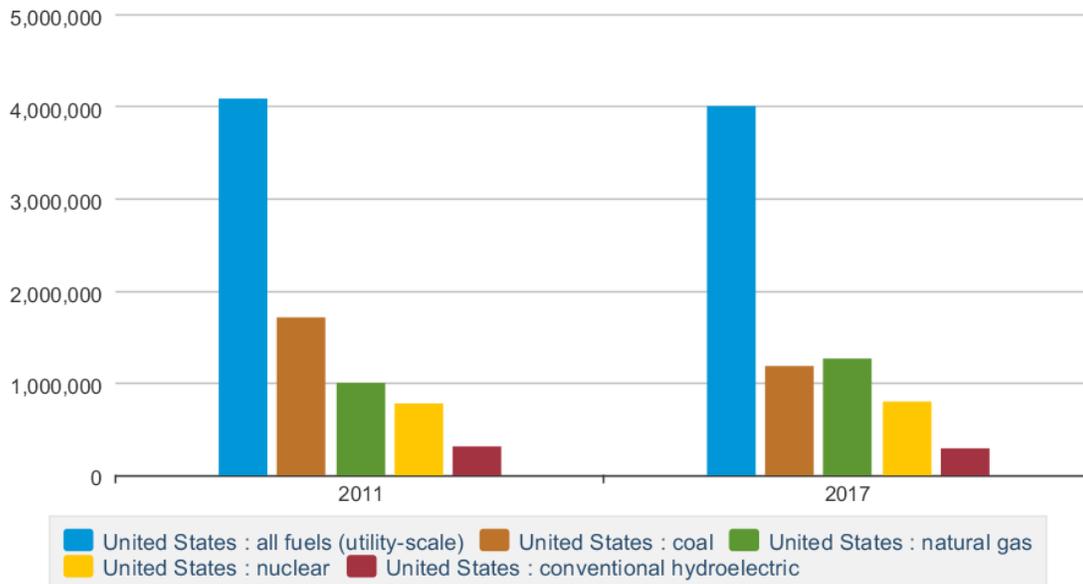
thousand megawatthours



Data source: U.S. Energy Information Administration

Net generation for all sectors, Annual

thousand megawatthours



Data source: U.S. Energy Information Administration

Figure 8-1 Charts of Historic U.S. Net Generation⁵⁶

⁵⁶ (EIA Electricity Data, 2017)

As Basin Electric evaluates the need for power supply, Basin Electric must consider what is going on around us and perform an analysis of the regional power supply system. Basin Electric employs the views of various governmental reports, industry expert's projections and the actual planning area or NERC Regional Reliability organization's future outlook. Basin Electric management and staff take an active role in each organizations business practice and operational working groups. These groups are a collaboration of stakeholders that facilitate rules, regulations and process creations for each area.

Basin Electric's service territory lies within the Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO) in the eastern interconnection and the Rocky Mountain Reserve Group (WECC-RMRG), and Northwest Power Pool (WECC-NWPP) NERC assessment sub-regions in the western interconnection.



Figure 8-2 NERC Assessment Areas

Southwest Power Pool (SPP)

SPP Demand

Basin Electric reviews the forecasted demand for the SPP market disclosed by the NERC 2017 Long-Term Reliability Assessment (LTRA), various industry experts planning scenarios, SPP 2019 Integrated Transmission Plan (ITP) and SPP's 2018 Resource Adequacy Report. These forecasts shows SPP demand growing at a meager rate over the study period (See Figure 8-3). Demand side management activities such as increased energy efficiency and behind the meter generation have slowed retail energy demand, and will continue to do so into the future. Local pockets of growth, such as from new oil and gas developments, will be required to be monitored, but for the vast majority of SPP demand is projected to be flat to a 0.5% growth.

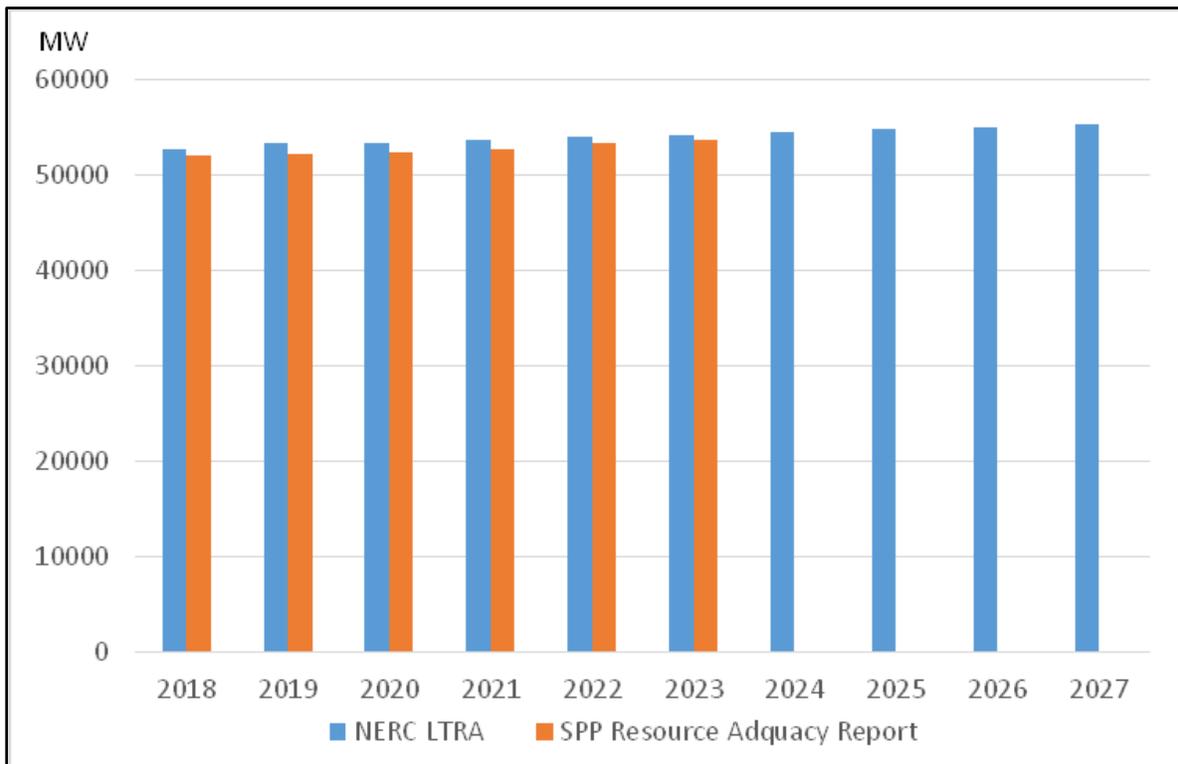


Figure 8-3 SPP Demand Outlook⁵⁷⁵⁸

⁵⁷ (NERC Long Term Reliability Assessment, 2017)

⁵⁸ (SPP Resource Adequacy Report, 2018)

SPP Generation

The SPP footprint in the central Midwest creates opportunities for wind expansion. Berkeley Lab has developed the following wind capacity factor by state, showing the majority of SPP being within the dark blue region (39%-42% capacity factor). (See Figure 8-4)

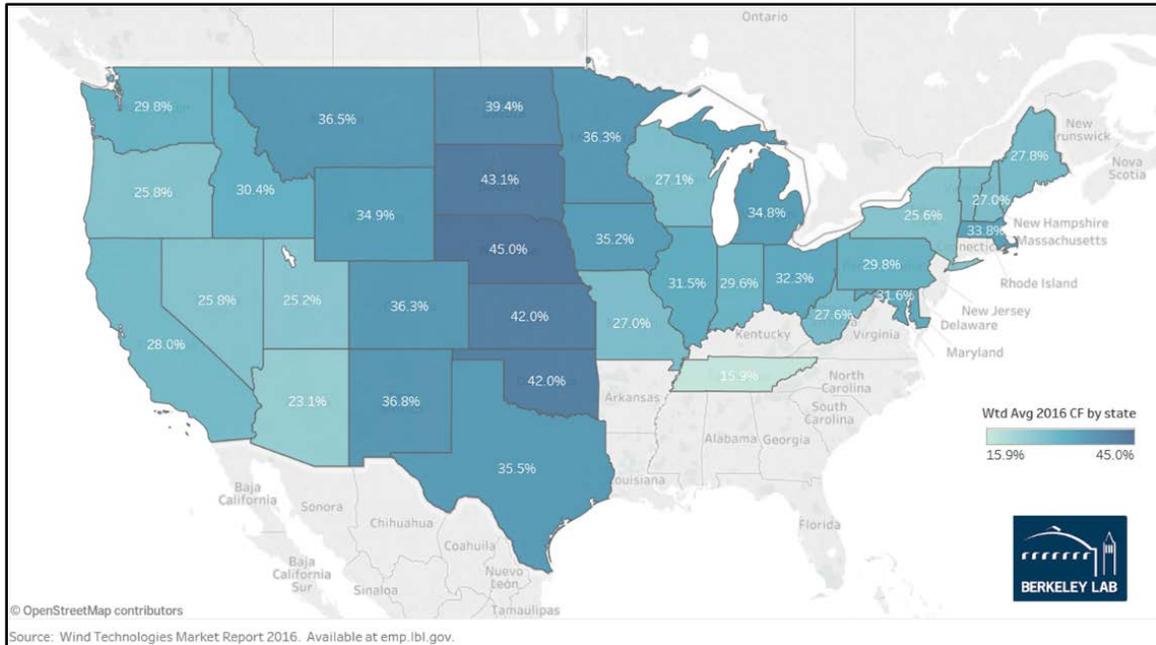


Figure 8-4 Berkeley Lab Wind Capacity Factor by State⁵⁹

Historically the SPP generation has consisted of an equal share of Coal and Natural Gas generation supplying the lion’s share of the energy in SPP. With the increasing renewable wind and solar buildouts this metric has begun to shift. This phenomenon is also being forecasted by industry experts and SPP alike, all showing a massive influx in renewable generation. The SPP Generation Interconnection Queue, (a listing of projects looking to gain access to SPP’s transmission) has over 45 GW of wind and 17 GW of solar in various stages of acceptance in the next three years. While Basin Electric doesn’t believe all these projects will come to fruition, industry experts believes that installed wind capacity in SPP will approach 30 GW and solar will approach 2.5 GW in the next 5 years. The development of wind and solar is expected to slow down after the federal renewable energy tax credits expire (more details on these renewable energy tax credits can be found on page 24 under “Federal Renewable Energy Tax Credits” towards the end of Chapter 4 The Planning Environment). After that time, wind and solar expansion should continue but at much slower pace as the economic benefits of the tax credits have been phased out.

As these new resources come online and start to serve load the future generation retirements for coal, gas and nuclear will need to be assessed. Industry assumptions vary on retirements from source to source, anywhere from 1.8 GW to 6.3 GW out to 2023. Basin Electric will continue to monitor announced retirements

⁵⁹ (Berkeley Labs Wind Technology Market Report, 2017)

as they are made public and be sure to use this information to drive informed decisions about the changing resource makeup of SPP.

The non-dispatchable nature of intermittent wind and solar generation has been a topic of discussion at SPP. The availability of these units to provide electricity at the time of the peak load hours has brought about the debate of whether you can use these resources to meet your planning reserve margin requirements. The current process is detailed in the SPP Planning Criteria document. It allows for the accreditation of capacity for these resources to be determined by how much power is output during the top 3% of load hours each month of the year. These output values are sorted from high to low and the value with a confidence level of 60% or higher becomes the accredited capacity amount for the intermittent resource. The resultant is that wind and solar are accredited for something less than their nameplate value. Wind in the summer months is often time only receiving 10-12% capacity accreditation. Solar accreditation in SPP is averaging approximately 80% accreditation. This is shown in Figure 8-5, that although there is over 19 GW of wind capacity in SPP, it has an accreditation of 1,863 MW. This will be exaggerated as dispatchable coal, gas and nuclear retire and wind and solar are added to the system.

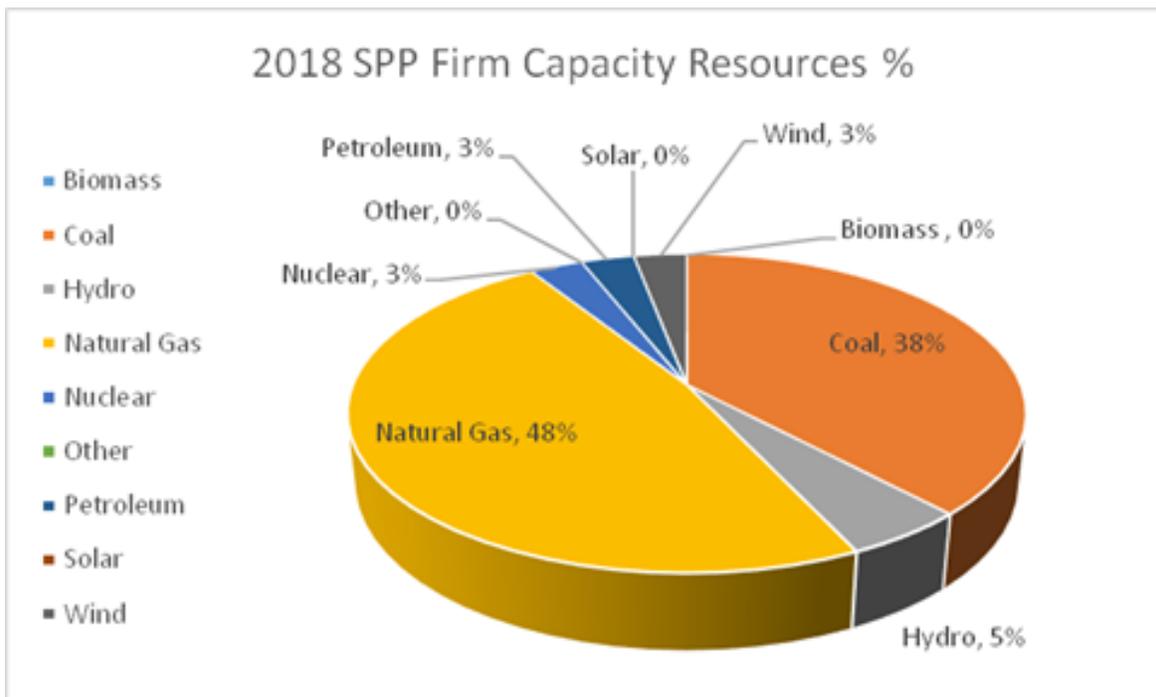


Figure 8-5 SPP Firm Accredited Capacity Resources (%)⁶⁰

⁶⁰ (SPP Resource Adequacy Report, 2018)

SPP Planning Reserve Margins

Basin Electric reviews the forecasted planning reserve margin for the SPP market as disclosed by the NERC 2017 Long-Term Reliability Assessment (LTRA), various industry experts planning scenarios and SPP's 2018 Resource Adequacy Report. All forecasts have SPP exceeding the minimum required Planning Reserve Margin of 12% throughout their study period. (See Figure 8-6) The planning reserve margin differences are driven by slightly different views on load growth, future portfolio buildouts, and the assumptions on retirement of legacy resources. SPP's load growth and changing generation portfolios will be monitored by Basin Electric in order to make long term resource decisions.

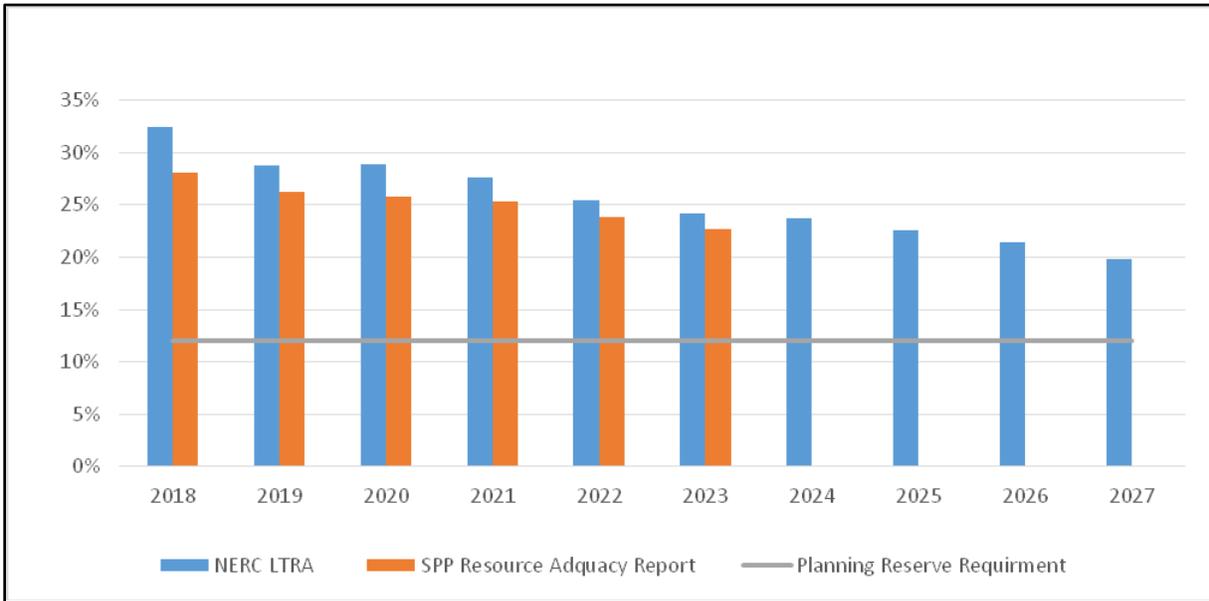


Figure 8-6 SPP Planning Reserve Margins^{61,62}

⁶¹ (NERC Long Term Reliability Assessment, 2017)

⁶² (SPP Resource Adequacy Report, 2018)

Midcontinent Independent System Operator (MISO)

MISO Demand

The forecasted 10-year Demand Outlook in MISO through the assessment period (2018-2027) is shown in Figure 8-7 below. Basin Electric reviews the forecasted demand for the MISO market disclosed by the NERC 2017 Long-Term Reliability Assessment (LTRA), various industry expert planning scenarios, and MISO's 2018 Transmission Expansion Plan Report (MTEP). The forecasts shows MISO's demand growing at a meager rate over the study period. Demand side management activities such as increased energy efficiency and behind the meter generation have slowed retail energy demand, and will continue to do so into the future. Both MISO MTEP and the NERC LTRA have a decreasing load forecast starting in 2025.

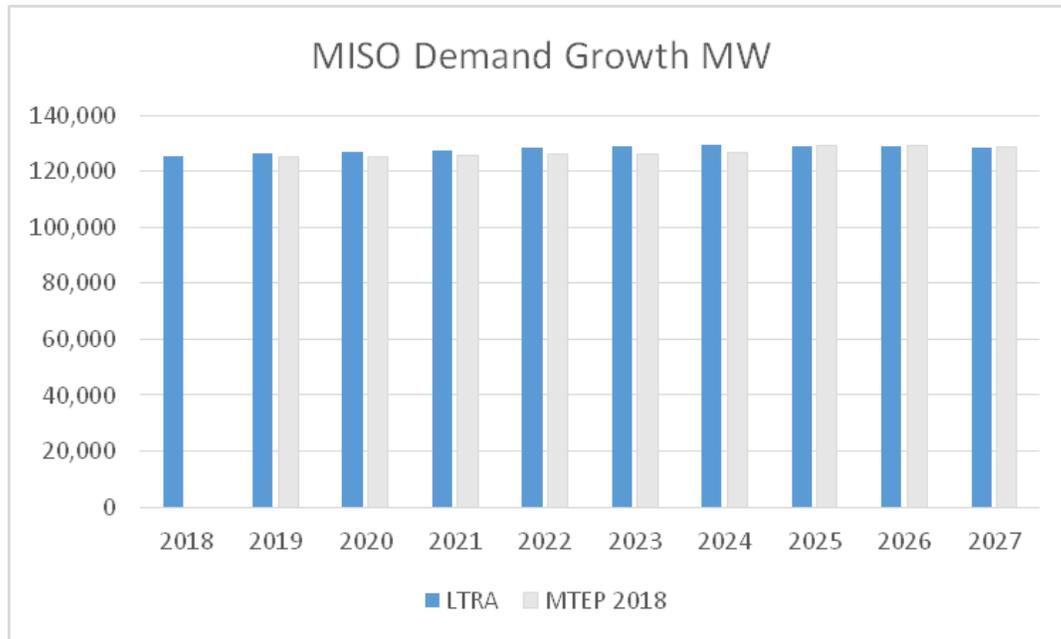


Figure 8-7 MISO Demand Outlook⁶³⁶⁴

MISO Generation

MISO currently has 170,500 MW of nameplate resources available and 140,200 MW of accredited capacity available to meet planning reserve margins. As with SPP, MISO's footprint in the central Midwest also creates opportunities for wind expansion. The western edge of MISO is shown being within the dark blue region (39%-42% capacity factor) with the central portion lying within the light blue region of 32%-36%. (See Figure 8-4)

Historically the MISO generation has consisted of an equal share of Coal and Natural Gas generation supplying the lion's share of the energy within MISO. (See Figure 8-8). With the increasing renewable wind and solar buildouts this metric has begun to shift. This phenomenon is also being forecasted by industry experts and MISO alike, all showing a massive influx in renewable generation. The MISO Generation Interconnection Queue, (a listing of projects looking to gain access to MISO's transmission) has over 42 GW of wind and 37 GW of solar in various stages of acceptance in the next three years. While Basin Electric doesn't believe all these projects will come to fruition, industry experts believe that installed wind capacity in MISO will

⁶³ (MISO MTEP, 2018)

⁶⁴ (NERC Long Term Reliability Assessment, 2017)

approach 33 GW and solar will approach 7.5 GW in the next 5 years. The expiration of the Production Tax Credit (PTC) will slow down development after 2020 out until it ends in 2023. Post 2023 wind expansion should continue but a much slower pace as the economic benefits of the PTC have been phased out.

As these new resources come online and start to serve load the future generation retirements for coal, gas and nuclear will need to be assessed. Industry assumptions vary from source to source, but the MISO MTEP is estimating 3,848 MW of generation capacity is retiring in 2018 and an additional 359 MW of generation capacity will retire in 2019. Basin Electric will continue to monitor announced retirements as they are made public and be sure to use this information to drive informed decisions about the changing resource makeup of MISO.

The non-dispatchable nature of intermittent wind and solar generation has been a topic of discussion at MISO. The availability of these units to provide electricity at the time of the peak load hours has brought about the debate of whether you can use these resources to meet your planning reserve margin requirements. The current 2 step process is detailed in the MISO Wind Capacity Credit report, first a probabilistic approach is used to determine the MISO Effective Load Carrying Capability (ELCC) value for all wind resources in MISO and then use a deterministic method employing the historical wind resource output of each, which is then allocated across all wind Commercial Pricing Nodes. For the 2018-2019 planning year 15.2 percent was established as the accreditation⁶⁵ factor for wind. For MISO's solar resources a solar capacity credit of 50 percent was established for the 2018-2019 planning year by using historical data to determine the solar contribution to the peak period. This will be exaggerated as dispatchable coal, gas and nuclear retire and wind and solar are added to the system.

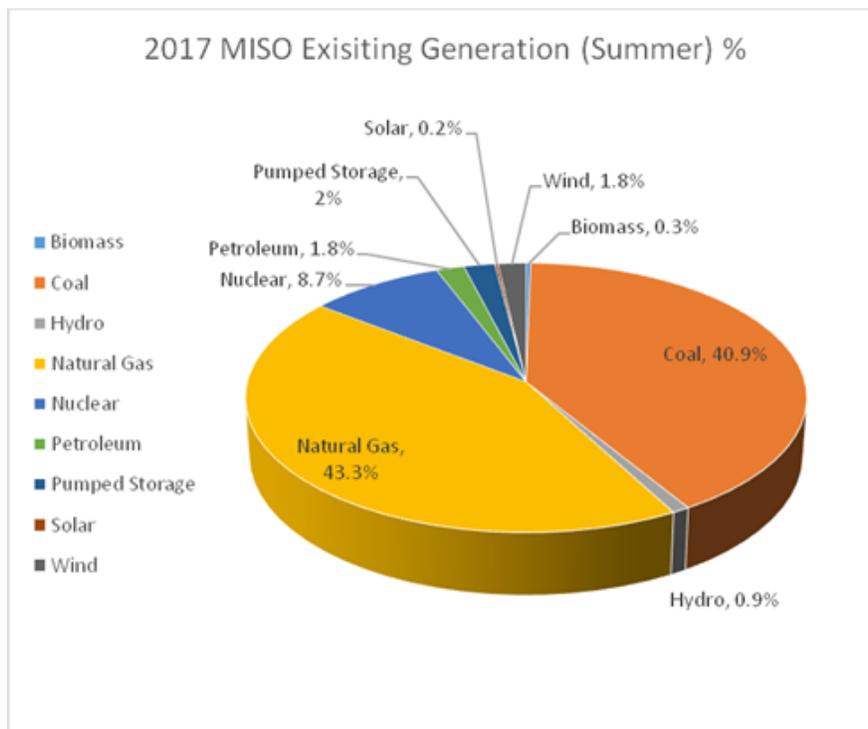


Figure 8-8 MISO Generation Summer (%)⁶⁶

⁶⁵ (MISO Wind Capacity Report, 2018)

⁶⁶ (NERC Long Term Reliability Assessment, 2017)

MISO Planning Reserve Margins

Basin Electric review the forecasted planning reserve margin for the MISO market disclosed by the NERC 2017 Long-Term Reliability Assessment (LTRA), various industry expert planning scenarios and MISO's 2018 MISO Transmission Expansion Plan (MTEP). The forecasts are project to exceed the minimum required Reserve Margin of 17.1% through 2021/2022 year, and a less than adequate Planning Reserve Margin for each of the remaining years of the assessment period (See Figure 8-9). The planning reserve margin differences are driven by slightly different views on load growth, future portfolio buildouts, and the assumptions on retirement of legacy resources.

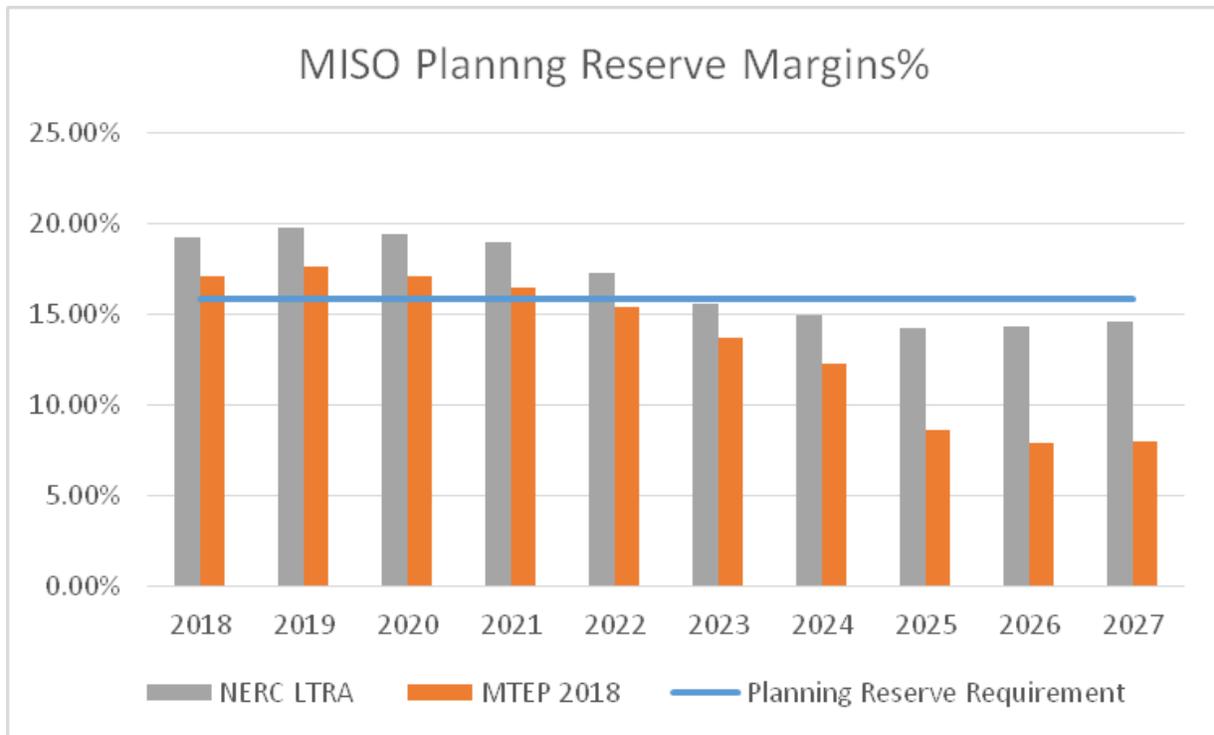


Figure 8-9 MISO Planning Reserve Margins⁶⁷⁶⁸

⁶⁷ (MISO MTEP, 2018)

⁶⁸ (NERC Long Term Reliability Assessment, 2017)

Western Electricity Coordinating Council - Rocky Mountain Reserve Group (WECC-RMRG)

WECC-RMRG Demand

Basin Electric reviews the forecasted demand for the WECC RMRG market disclosed by the NERC 2017 Long-Term Reliability Assessment (LTRA), various industry experts planning scenarios, and WECC's 2016 Power Supply Assessment. The forecasts shows RMRG's demand growing at a meager rate over the study period (See Figure 8-10). The WECC updates the peak and energy forecasts based on expected population growth with expected economic conditions and normalized weather conditions. Local pockets of growth, such as from new oil and gas developments, will be required to be monitored. There is an abundance of coal fields in the RMRG area, Basin Electric will continue to monitor any load changes as a result of low gas prices and increased renewable buildouts.

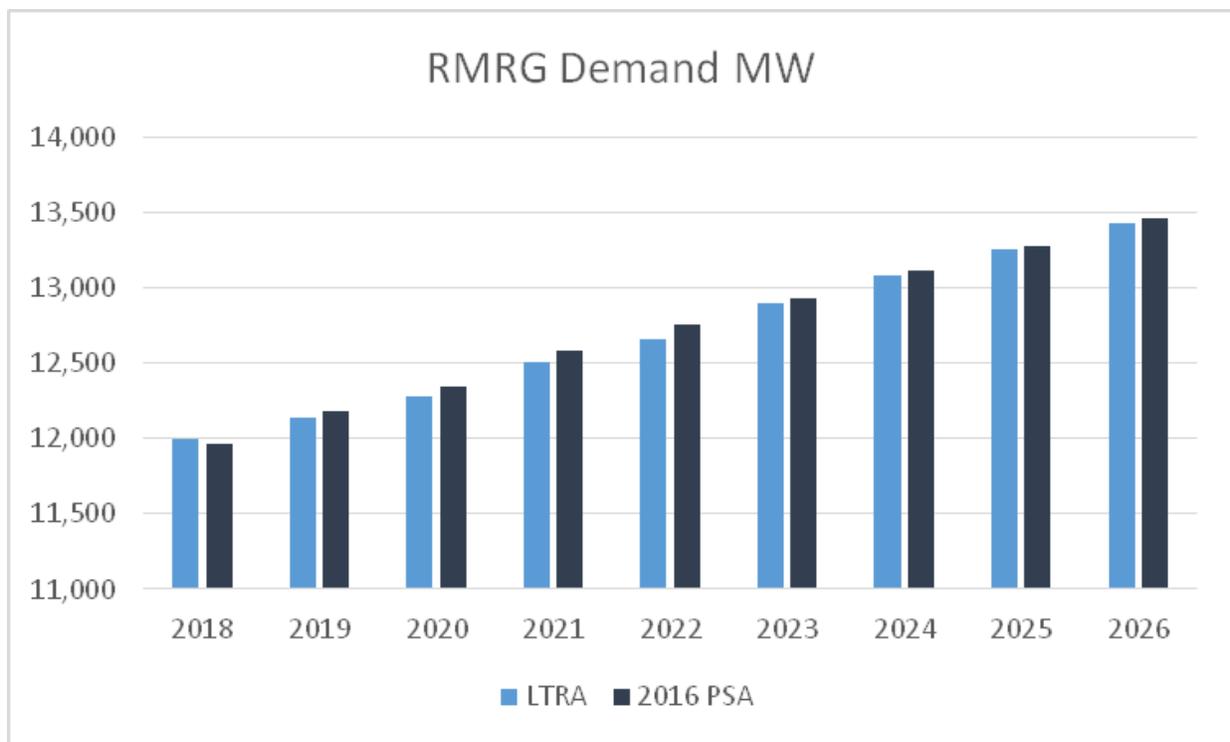


Figure 8-10 WECC-RMRG Demand⁶⁹⁷⁰

⁶⁹ (WECC Power Supply Assessment, 2016)

⁷⁰ (NERC Long Term Reliability Assessment, 2017)

WECC-RMRG Generation

Historically the RMRG generation has consisted of over 50% Coal and 35% Natural Gas generation suppling the lion's share of the energy within RMRG. There is increasing renewable wind and solar buildouts shown in both WECC and industry experts forecasts, especially in the Colorado and Wyoming areas. The Public Service of Colorado, Tri-State G&T Association, Common Use, and Western Area Power's Generation Interconnection Queues, (a listing of projects looking to gain access to transmission) has over 23 GW, 2.1 GW, 680 MW and 1.9 GW, respectively, in various stages of acceptance in the next three years. While Basin Electric doesn't believe all these projects will come to fruition, industry experts believe that installed wind and solar capacity in RMRG will approach 7.5 GW of wind and solar will approach 2.1 GW in the next 5 years. The expiration of the Production Tax Credit (PTC) will slow down development after 2020 out until it ends in 2023. Post 2023 wind expansion should continue but a much slower pace as the economic benefits of the PTC have been phased out. Figure 8-11 WECC-RMRG Summer Generation (%) below shows the 2017 capacity breakdown by fuel type in the WECC-RMRG region.

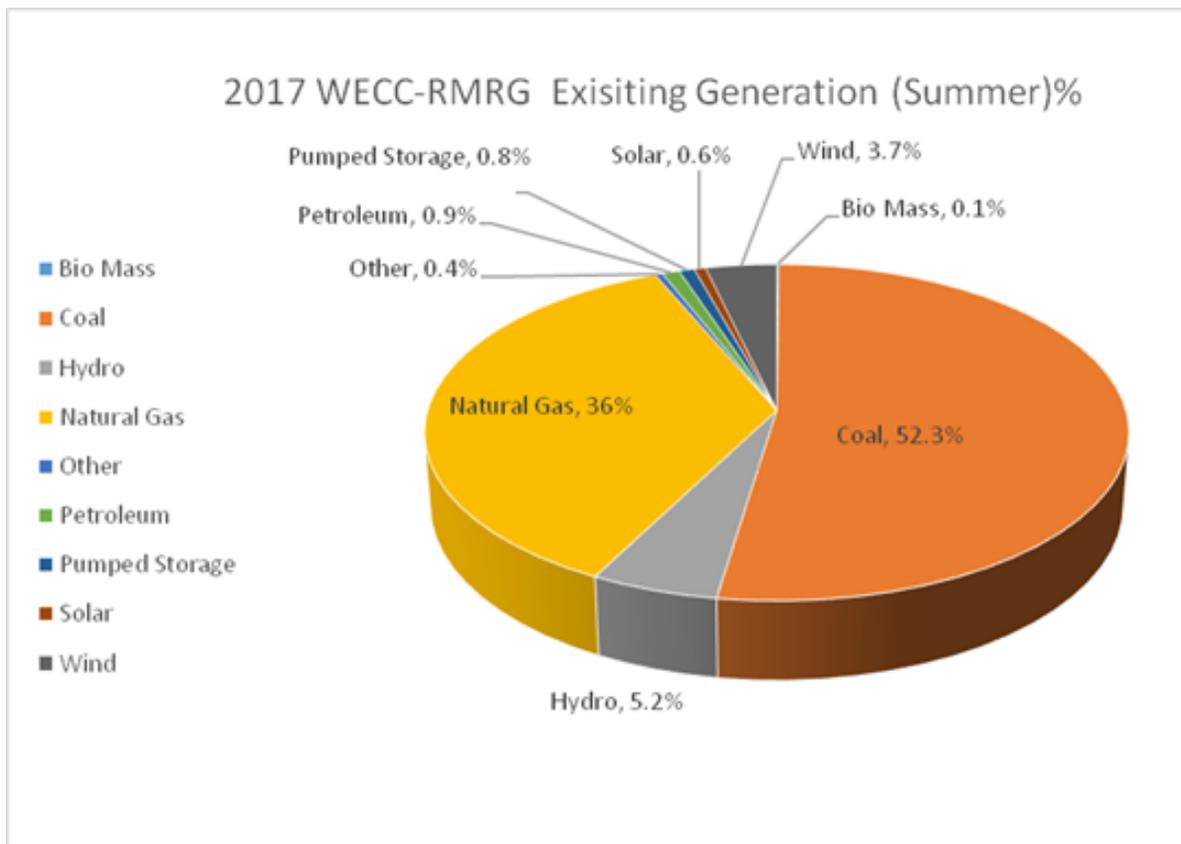


Figure 8-11 WECC-RMRG Summer Generation (%)⁷¹

⁷¹ (NERC Long Term Reliability Assessment, 2017)

WECC-RMRG Planning Reserve Margins

RMRG is projecting adequate planning reserve margins during the 2018-2027 assessment period. Planning reserve margins exceed the NERC Reference Margin Level of 14.17 % (See Figure 8-12). This market outlook is derived from the NERC LTRA and the WECC 2016 Power Supply Assessment (PSA). There is no planning reserve margin required today in the RMRG region. The entities within the RMRG area are subject to WECC contingency reserve obligations detailed in BAL-002-WECC-2, which states that an entity has to hold in reserves which is the greater of: a) the most severe single contingency, or b) 3% of its load and 3% of its generation. Basin Electric holds these contingency reserves with its coal and gas units.

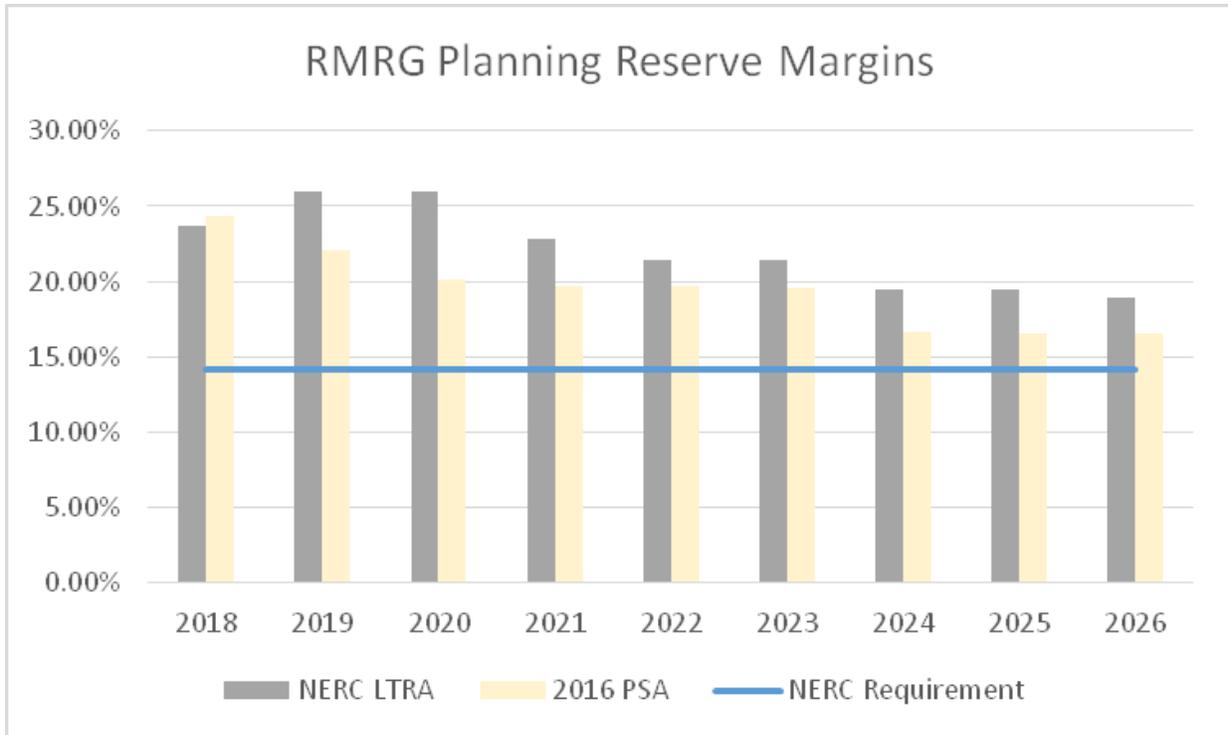


Figure 8-12 WECC-RMRG Planning Reserve Margins⁷²⁷³

⁷² (WECC Power Supply Assessment, 2016)

⁷³ (NERC Long Term Reliability Assessment, 2017)

Western Electricity Coordinating Council - Northwest Power Pool (NWPP)

WECC-NWPP Demand

Basin Electric reviews the forecasted demand for the WECC RMRG market disclosed by the NERC 2017 Long-Term Reliability Assessment (LTRA), various industry experts planning scenarios, and WECC's 2016 Power Supply Assessment). The forecasts shows NWPP's demand growing at a meager rate over the study period. (See Figure 8-13). The WECC updates the peak and energy forecasts based on expected population growth with expected economic conditions and normalized weather conditions. Basin Electric will continue to monitor any load changes that may result in the future.

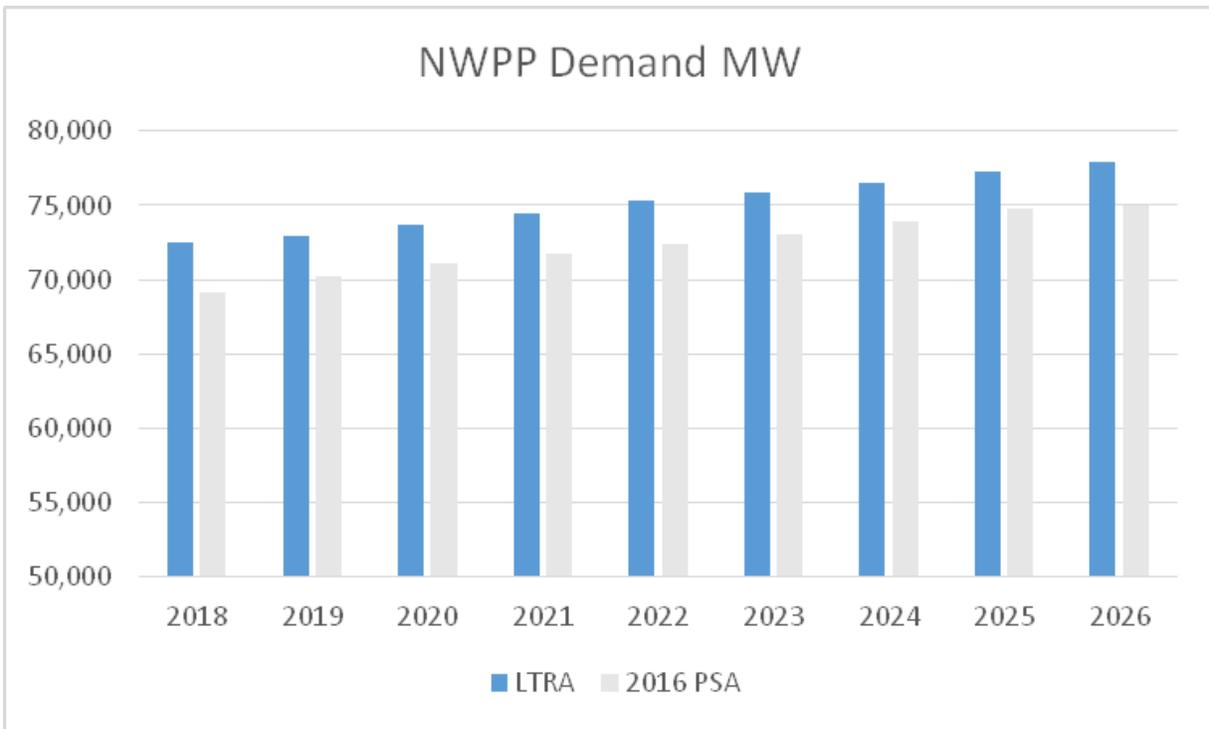


Figure 8-13 WECC-NWPP Demand Growth (MW)⁷⁴⁷⁵

⁷⁴ (WECC Power Supply Assessment, 2016)

⁷⁵ (NERC Long Term Reliability Assessment, 2017)

WECC-NWPP Generation

Historically the NWPP generation has consisted of over 40% Hydro and 35% Natural Gas generation supplying the lion's share of the energy within NWPP (Figure 8-14 WECC-NWPP Generation Summer). The members in NWPP have worked to reduce the amount of coal and nuclear generation, especially those entities on the western edge of the power pool. Today coal and nuclear represent less than 18% of the overall capacity. Most of this will likely be replaced in the future by economic wind, solar and gas. The expiration of the Production Tax Credit (PTC) will slow down development after 2020 out until it ends in 2023. Post 2023 wind expansion should continue but a much slower pace as the economic benefits of the PTC have been phased out

Since Basin Electric's load obligations are in NWPP are in the extreme eastern portion of subregion and that Basin Electric has committed to serving this area either coming from the east across the Mile City DC tie or from Purchase Power Agreements, Basin Electric has enough capacity out to the end of this study period.

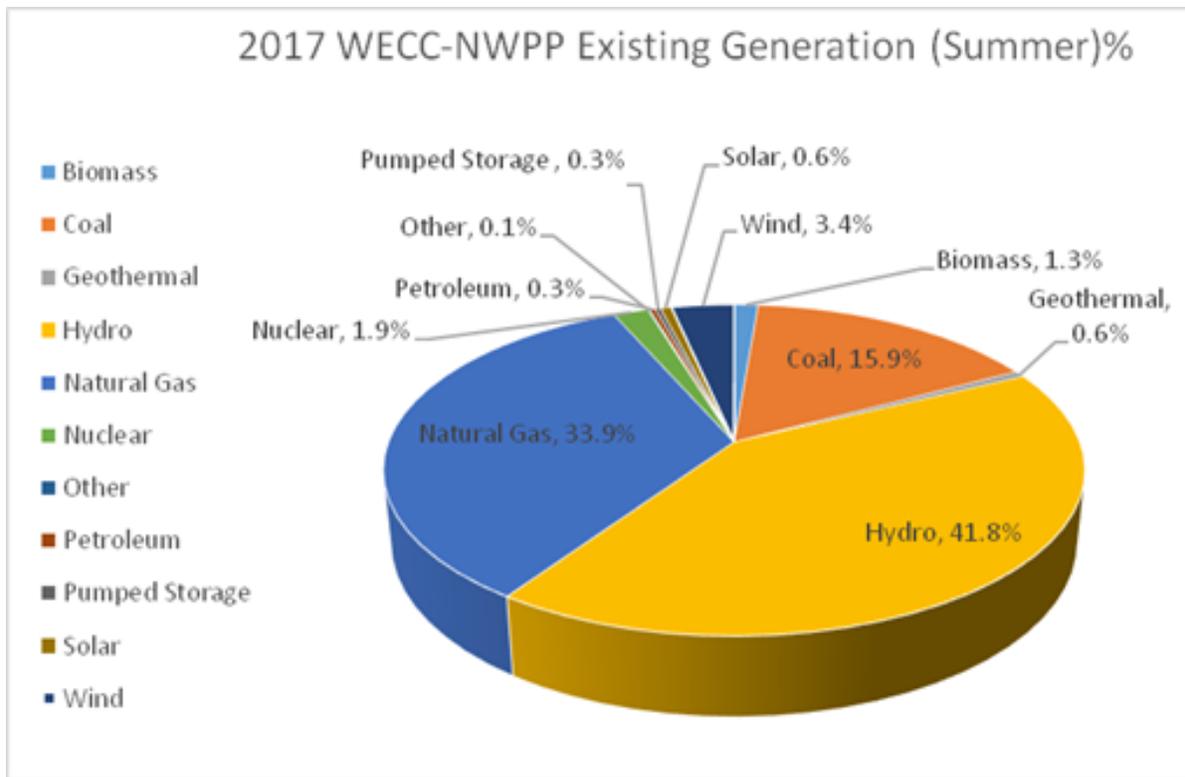


Figure 8-14 WECC-NWPP Generation Summer (%)⁷⁶

⁷⁶ (NERC Long Term Reliability Assessment, 2017)

WECC-NWPP Planning Reserve Margin

NWPP is projecting adequate Planning Reserve Margins during the 2018-2026 assessment period. The Planning Reserve Margin exceeds the NERC Reference Margin Level of 16.38 %. (Figure 8-15 WECC-NWPP Planning Reserve Margins). This market outlook is derived from the NERC LTRA and the WECC 2016 Power Supply Assessment (PSA). There is no planning reserve margin required today in the NWPP region. The entities within the NWPP area are subject to WECC contingency reserve obligations detailed in BAL-002-WECC-2, which states that an entity has to hold in reserves which is the greater of: a) the most severe single contingency, or b) 3% of its load and 3% of its generation. Basin Electric fulfills this contingency reserve obligation with purchases from the transmission provider in the NWPP.

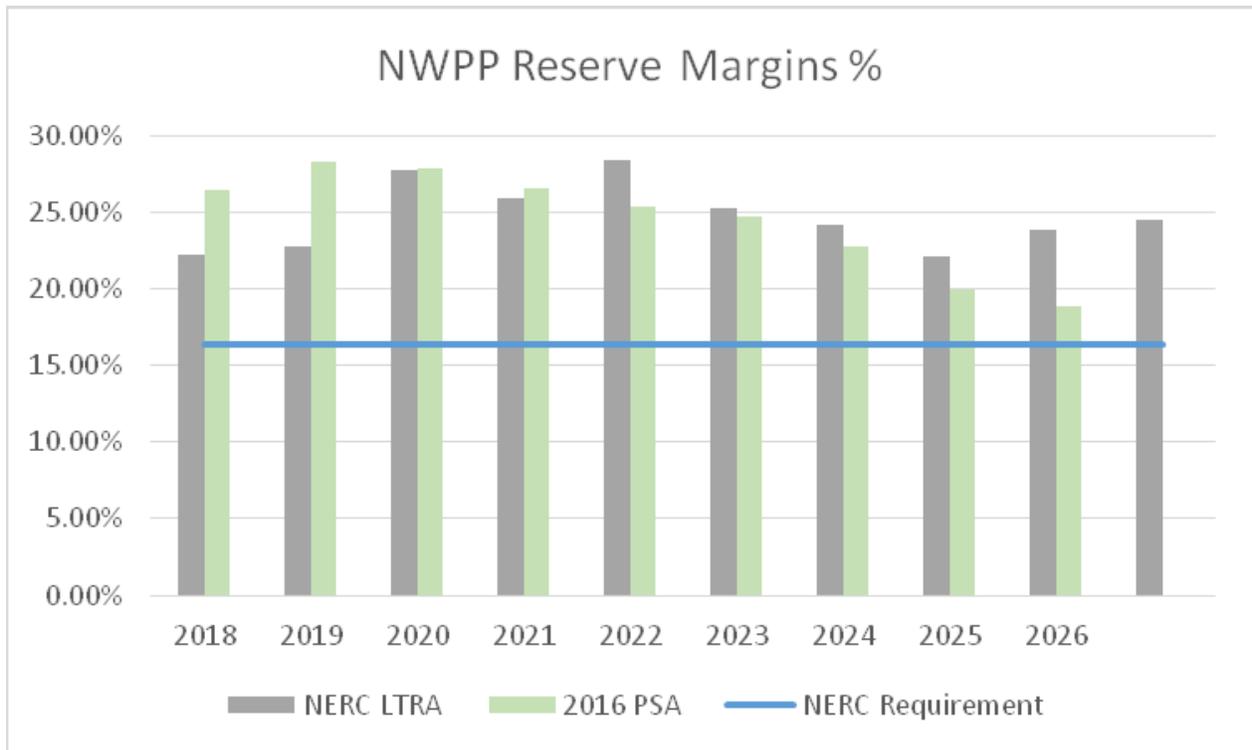


Figure 8-15 WECC-NWPP Planning Reserve Margins⁷⁷⁷⁸

⁷⁷ (WECC Power Supply Assessment, 2016)

⁷⁸ (NERC Long Term Reliability Assessment, 2017)

9) Analytical Approach

Introduction

Basin Electric's analytical approach to meeting future member power requirements consists of multiple steps, with which many have already been discussed in previous chapters. The first two steps, the development and approval of the member load forecast as well as the analysis of Basin Electric's power supply needs on a capacity and energy basis, were discussed in Chapter 6) Load and Resource Balance.

Once it is determined when new power supply will be needed to meet forecasted member power obligations, market conditions in the various power supply regions discussed in Chapter 8) Regional Power Supply Analysis needs to be assessed to see if neighboring utilities are expected to have excess power that they may be willing to sell at a market price. These prices for market power are compared to the cost of building new resources. Market prices for bilateral arrangements are determined by issuing a Request for Proposals (RFP) for power supply. Our most recent attempts are discussed at the end of Chapter 4) The Planning Environment under as well as Chapter 7) Resource Alternatives under the Market Purchases section.

After we can determine if we can secure additional power supply through bilateral contracts with neighboring utilities at economically justifiable prices and know the duration in which that power supply can be secured, we then utilize all of the above information as an input into the power supply model discussed below to determine the optimal long term power supply expansion alternatives outside of what we are able to secure through the RFP process if needed.

Modeling Process for Long Term Power Supply Analysis

Basin Electric uses the modeling software Aurora developed by EPIS. Aurora has the capability to perform portfolio optimization using a risk-reward framework and a linear optimization model. The goal of the optimization is to calculate a number of optimal portfolios. Those portfolios with the highest reward and lowest risk given the constraints of the portfolio and its acquirable resources. Each portfolio found by the simulation will lie along the efficient frontier, which means that no other portfolio with higher reward at the same risk level exists, and no other portfolio with lower risk at the same reward level exists. The final result of the optimization will produce a set of one or more portfolios along this risk/reward frontier. The modeling process consists of 6 key steps

1. Base Case Development

To start, a base case is developed that incorporates changes at Basin Electric, as well as regional changes in power supply, transmission, load forecasts, and current projections of various fuel prices are incorporated in the Aurora modeling software. (Figure 9-1 Base Case Build) shows the inputs to from the base case. The Aurora modeling software can produce monthly or multiple-year ahead investment plans to meet long term reliability requirements.

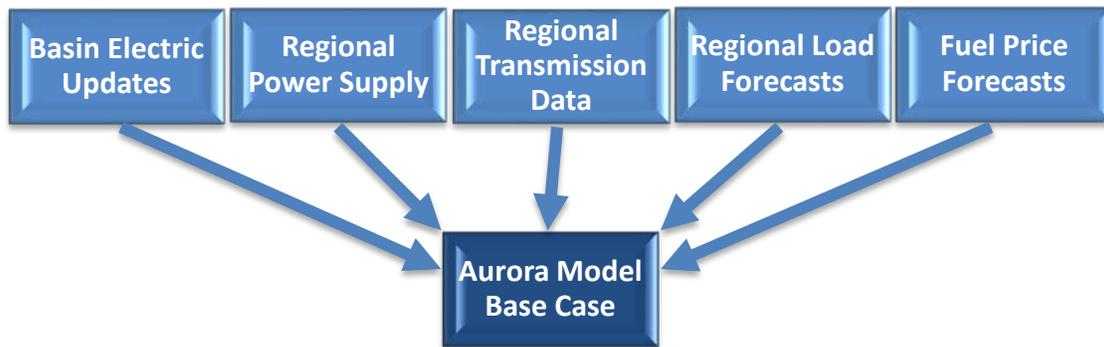


Figure 9-1 Base Case Build

After the base case has been developed, new project alternatives or purchases can be added. These projects can range from Request for Proposals (RFP) or self-build options. The software will analyze these new resources or purchases in developing the optimal resource portfolio for Basin Electric’s long term power supply needs.

2. Operational Simulation

Multiple risk base scenarios are performed to see what, if any changes, there are to what Aurora outputs as the best possible resource expansion plan portfolios. The model is run to simulate a monthly or a multiple year ahead study period. The results display a breakdown of the cost to operate the Basin Electric system including all existing and new resources, capacity factors, market purchases and market sales. The data provided by the Aurora model run helps to answer questions about the costs to operate the Basin Electric system including all existing and new resources, economic dispatch of existing and future resources which includes unit capacity factors, as well as Basin Electrics reliance on the energy market for both purchases and sales.

3. Cost Analysis

Using the different cases the model can show what cases represent the best financial outcome along a timeline. The goal of using the model is to find the most cost effective path for the future. The Aurora model factors in costs for fuel, varying plant operations, unit start up, market contracts, and spot market purchases and sales. From here a consolidated model is developed to identify all costs to serve future member power requirements. This consolidated model includes the operational costs from the Aurora model, the new capital costs needed for new resources, costs of capacity purchases, and incremental transmission needed. Figure 9-2 shows a breakdown of the consolidated model process.

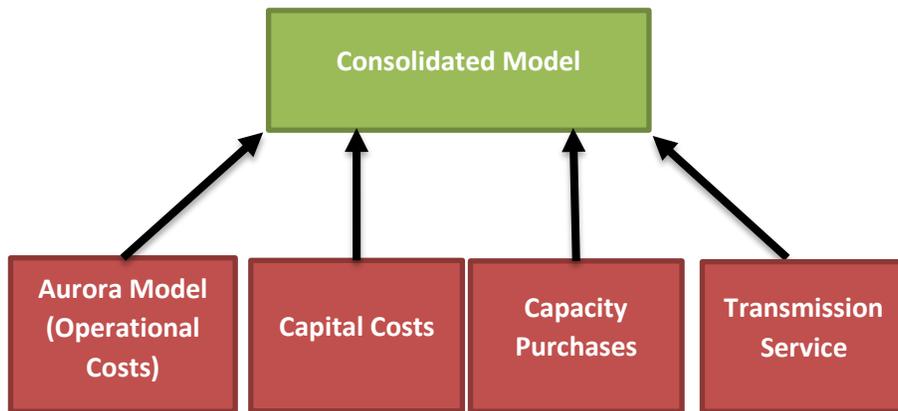


Figure 9-2 Consolidated Model Cost Analysis

4. Risk Analysis

Several risk scenarios are performed to test the portfolios. Some of these processes involve stressing natural gas prices, electric market prices, electrical load growth, new resource capital costs, regional renewable developments, and regional resource retirements. The process evaluates the performance of the specific portfolios under deterministic scenario simulations. Aurora outputs the best possible resource expansion plan. The end result of this risk analysis is a set of portfolios showing the most desirable results moving forward.

5. Selection of Preferred Portfolio

After all cases have been run, risks have been determined, and costs appropriately associated a preferred portfolio is developed and selected to move forward with.

6. Summary

Basin Electric's analytical approach analysis is comprehensive and results in the preferred portfolio of resource additions to meet the future needs of its members. The analytical approach is the general approach Basin Electric uses for long term resource expansion justification.

10) Risks and Uncertainties

Introduction

Electric utilities operate in a sometimes uncertain and volatile environment. There are increasing potential risks with fuel, including supply, transportation and emissions which in turn affect the market prices. Due to these increasing risks, it is prudent to perform a risk assessment to help determine how these potential risks affect Basin Electric's planning horizon and how operations can change with these risks.

Key Risks and Uncertainties

Load

Basin Electric does perform an in depth load forecast every year as described in chapter 5. This process produces a weather normalized forecast. While examining the load forecast there are uncertainty factors that need to be addressed that can cause variability in the forecast load. These consist mostly of weather, economics of the region, energy efficiency and demand side management. These topics were discussed as possible deviations in the Load Forecast section of the IRP.

Weather in the regions can shift a multitude of ways, hotter or colder temperatures than normal, wetter or dryer temperatures than normal. Basin Electric covers a large portion of the Upper Midwest which encompasses mainly agricultural production. If the weather is hot and dry it can affect crop production and irrigation loads, if it is cool and wet it can drive up agricultural crop drying load. These weather patterns also can drive heating and cooling loads, cooler than normal temps will drive higher furnace loads while hotter than normal temperatures will drive a larger air conditioner load.

Regional Economics can have a large effect on energy production loads (coal, oil and natural gas). The Bakken oil fields and the Powder River Basin coal fields are within Basin Electric's service territories. The loads associated with these globally traded commodities can vary greatly as the price fluctuates up and down. This risk affects the agricultural markets as well, as it is also a traded commodity. These drivers can affect large load additions to appear or disappear in the load forecast, such as processing or pipeline loads.

Energy efficiency and demand side management are continuing to reduce the load needed to be served from large scale generation. From light bulbs, to water heaters, and refrigerators all electric appliances have been expanding their energy efficiency ratings seemingly every year. Couple this energy efficiency with new innovative demand side management activities such as Behind the Meter Generation (BTMG) and grid supplied load obligations become even less. BTMG such as battery and roof top solar installations, and personal wind generators can greatly reduce the megawatt hours required from the grid. Demand side management also can entail special programs offered by the local or regional power supplier to move load between on and off peak hours for a special rate.

Even though the current load forecasting methodology tries to take these variables into account, it is prudent for Basin Electric to make efforts to follow these changing metrics and react planning wise in the most effective manner for our cooperative members. To do this, Basin Electric's planning activities often have scenario based models that stress our load forecast to see the possible changes that can result.

Natural Gas

The price of Natural Gas, according to the US Energy Information Administration is predicted to remain relatively flat from 2018-2019. Figure 10-1 Henry Hub Natural Gas Price Forwards \$/MMBtu shows historical Henry Hub Natural Gas Price from January 2014 through fall 2017 and projections for 2018 and 2019. This relatively flat projection extends past 2019, Basin Electric's third party industry experts forecast over 1,200 Tcf natural gas availability in North America at pricing at or below \$4.00/MMBtu for the foreseeable future. The future coal and nuclear retirements could increase as the price of natural gas stays low and it becomes a larger percentage of the energy supply mix. Basin Electric will continue to monitor the natural gas usage across the area and region to look for changes in trends. Another key point to watch is the hydraulic fracturing process that has unlocked most of this abundant gas supply. Any improvement gains or legislative losses will need to be evaluated as they occur. There are volatile times of natural gas pricing, but for the planning horizon Basin Electric feels that natural gas prices are stable out past this study time period.

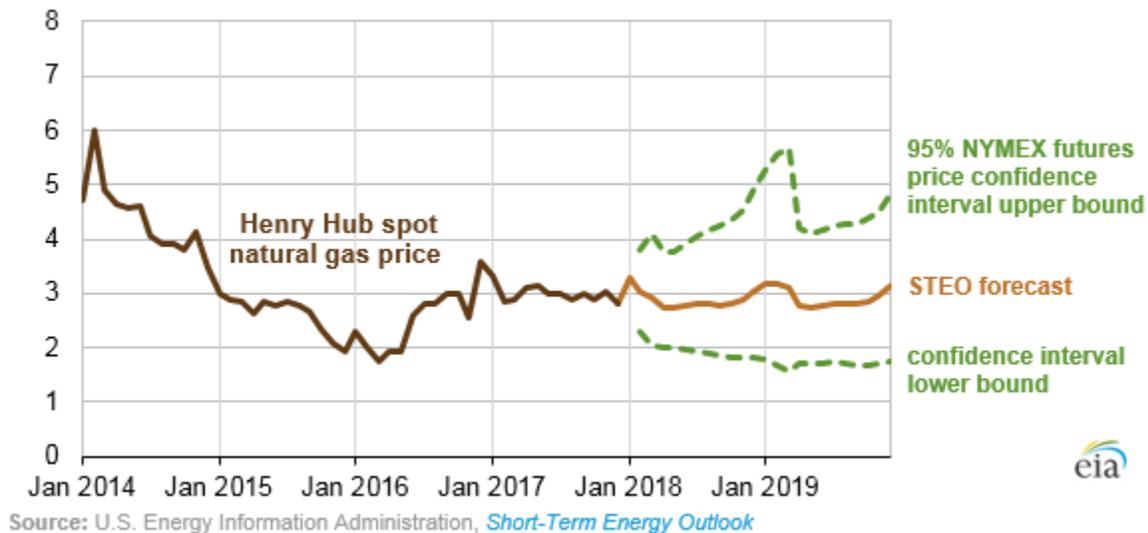


Figure 10-1 Henry Hub Natural Gas Price Forwards \$/MMBtu⁷⁹

⁷⁹ (Henry Hub Spot Price, eia.gov)

Wind & Solar Power

The wind Production Tax Credit (PTC), is set to expire in 2020 and all benefits from the PTC are ending in 2023. Figure 10-2 US Wind Capacity Additions below shows wind additions from 1998-2017. Industry experts and the ISOs themselves are all showing a massive influx in renewable generation. Currently all Generation Interconnection Queue, (a listing of projects looking to gain access to transmission system) are overloaded with wind project in various stages of acceptance in the next three years, so much so that many interconnection studies are backlogged by a year or more. While Basin Electric doesn't believe all these projects will come to fruition, Basin Electric believes that installed wind capacity in SPP and MISO will approach 30 GW in the next 5 years. The expiration of the Production Tax Credit (PTC) will slow down development after 2020 out until it ends in 2023. Post 2023 wind expansion should continue but at much slower pace as the economic benefits of the PTC have been phased out.

Currently the ITC for solar permits projects that either have started construction or have achieved safe-harbor provisions by the end of 2019 to receive the full 30% credit. Those meeting these requirements by 2020 receive 26% and if achieved by 2021 the credit is 22%. After 2021 the residential credit will expire. Businesses may still claim the credit after 2021 at a fixed permanent rate of 10%. The IRS has developed a two year timeframe for construction activities, those projects completing in 2021 are eligible to receive the 30% credit, and a completion in 2022 and 2023 to receive the 26% and 22% credits.

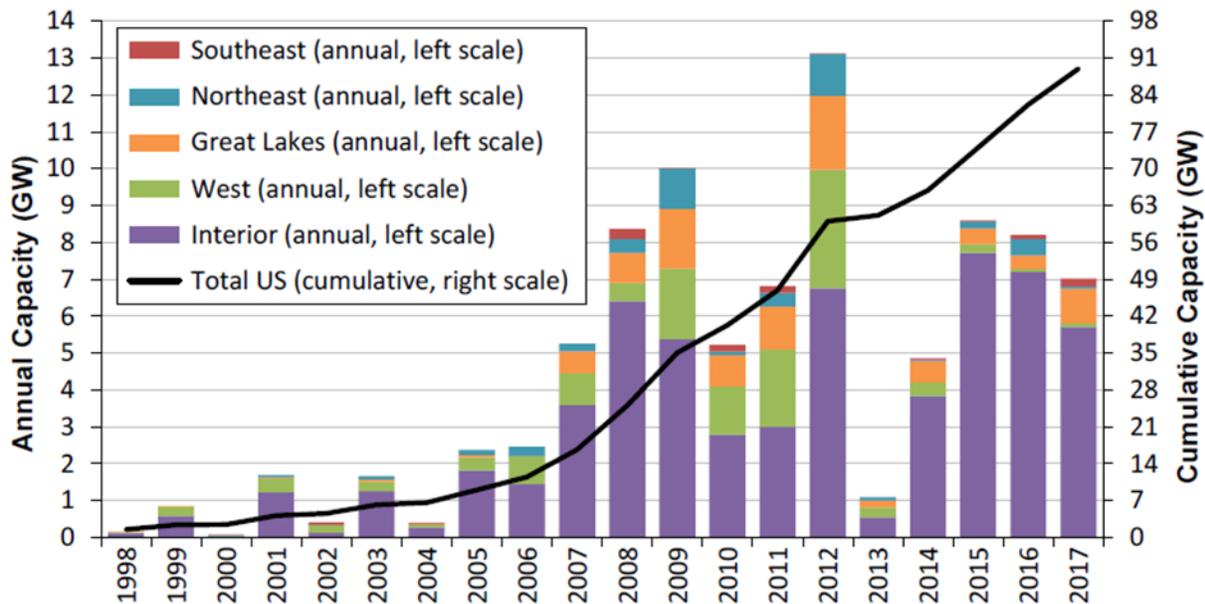


Figure 10-2 US Wind Capacity Additions⁸⁰

As the amount of renewable increases in each area it will put stress on the existing assets in the marketplace, mostly fossil fuel resources such as coal, natural gas and nuclear. This trend is already starting to appear with uneconomical coal and nuclear facility retirements being announced. This will weigh on each areas planning reserve margin requirements and the reliability of the system. As reports of wind and solar installations are reported and retirements announced Basin Electric will need to keep a watch on the regional planning reserve margin and the availability of market purchases to fulfill future power needs.

⁸⁰ (Wind Technologies Market Report)

Resource Retirements

As described in the previous sections, low natural gas pricing, low to no load growth, existing generation surpluses, significant renewable development and installations all translate into a lowering of the market pricing across all of Basin Electric's planning areas. These lower prices make it difficult for older baseload units to compete in a market based dispatch environment.

As conditions change and retirements are announced Basin Electric will need to keep a watch on the planning reserve margin and the availability of market purchases to fulfill future power needs.

Summary

All of the risks posed will affect the electric power prices and market conditions in the various planning areas Basin Electric operates in. These variables make it very challenging to forecast electric power prices going into the future. In this uncertain and volatile environment full of potential risks it is prudent to perform a risk assessment to help determine how these potential risks affect Basin Electric's planning horizon and how operations can change with these risks. Basin Electric has been monitoring these conditions and has tried to mitigate future risk by securing short term bi-lateral contracts that support Basin Electric's power supply needs. These contractual purchases push out the need to build new resources and ultimately creates a cliff event to more economically align the new resource timing with the market and our members load growth. We continue to work on solutions that support this strategy, yet continue to monitor market conditions, load growth and regional reserve margins that will directly impact the viability and economics of this strategy.

11) Conclusion

Summary

The 2018 IRP is intended to provide guidance and rationale for Basin Electric’s resource development options over the next several years. This section includes the major conclusions and recommendations from the 2018 IRP.

With the current coincident peak demand forecasts and Basin Electric’s power supply portfolio, including having made the decision not to extend the lease agreements with the owners of Antelope Valley Station Unit 2, there is a relatively near term need for capacity in a few of Basin Electric’s Power Supply Planning Regions. Based on this need, Basin Electric is recommending to move forward with bilateral purchases with neighboring utilities for their available surplus capacity in SPP, NWPP, and MISO.

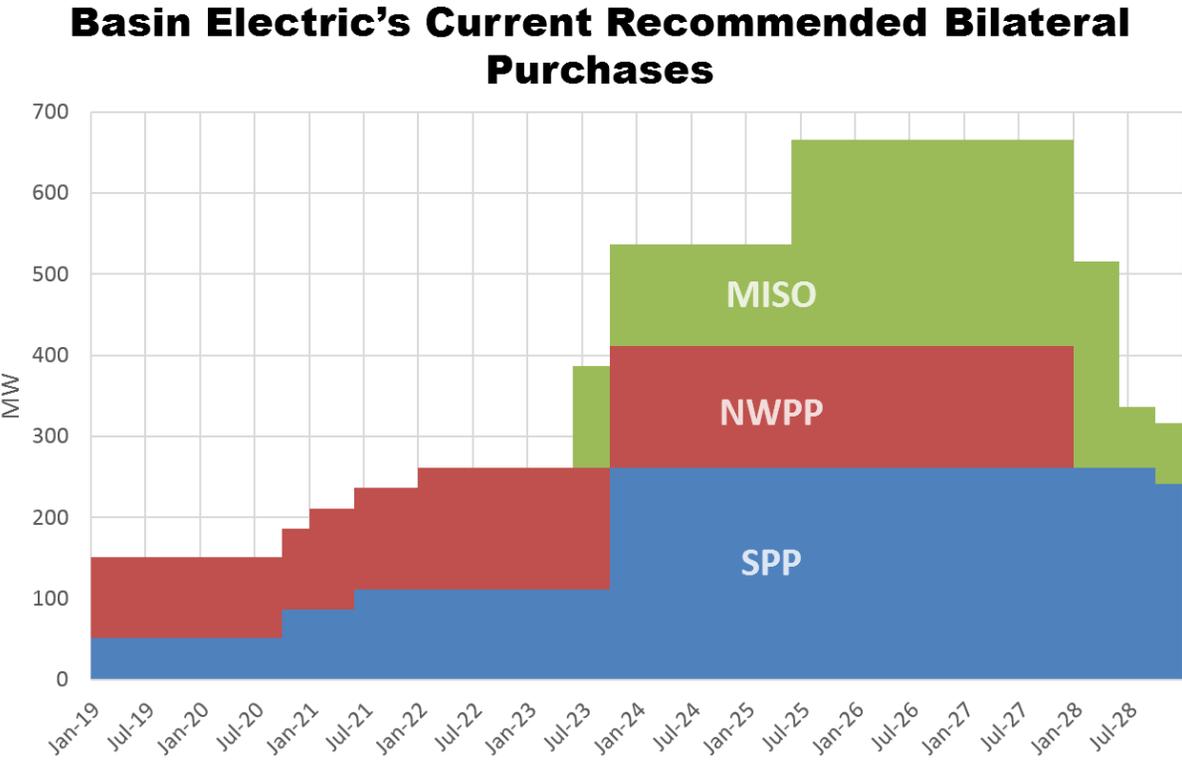


Figure 11-1 Basin Electric's Current Recommended Bilateral Purchases

Figure 11-2 through Figure 11-5 show Basin Electric’s revised summer season surplus (deficit) capacity positions in the RMRG, NWPP, MISO LRZ 1, and SPP regions with the recommended bilateral purchases. No changes are being proposed in the MISO LRZ 3 region at this time.

With the proposed bilateral purchases in the RMRG region, 50 MW of Basin Electric’s entitlement share of the Laramie River Station in the western interconnection/RMRG region will shift over to the unit in the eastern interconnection/SPP region. This will reduce the amount of surplus capacity that Basin Electric has in RMRG.

RMRG System Summer Surplus Capacity

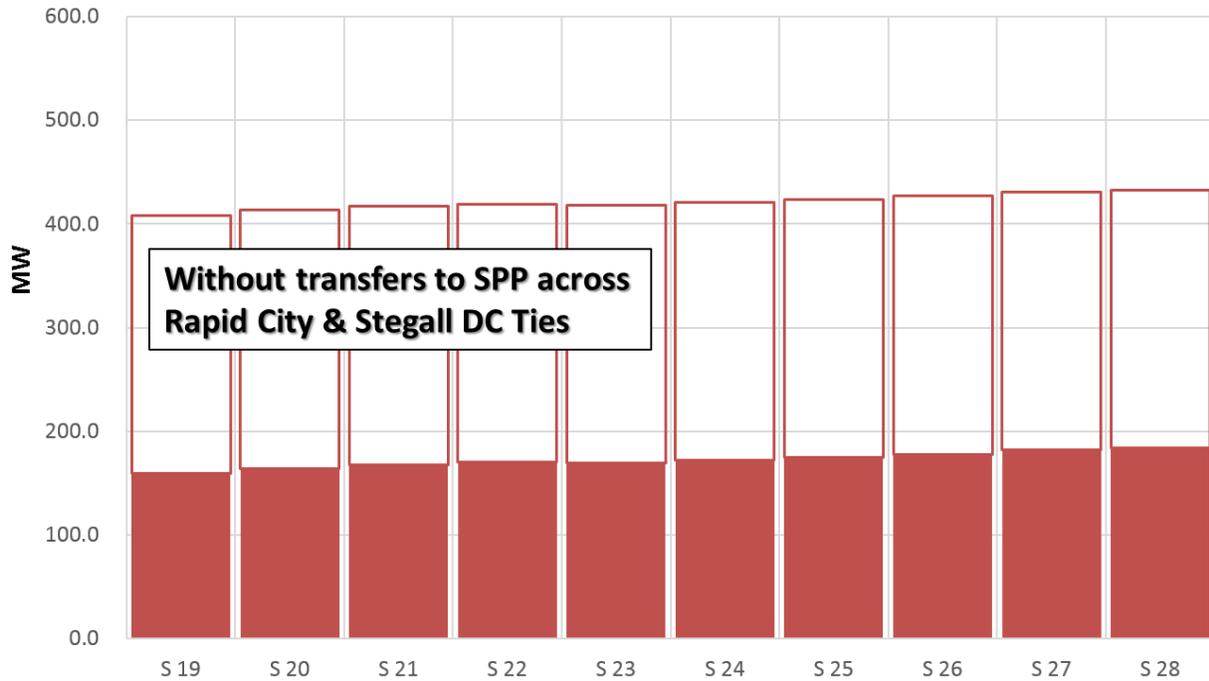


Figure 11-2 RMRG System Surplus Capacity with Current Recommended Bilateral Purchases

With the proposed bilateral purchases in the NWPP region, Basin Electric would not have to rely on supplying power from resources in SPP across the Miles City DC tie until 2026, at which time coincident peak demand obligations can still be met utilizing the Miles City DC tie until 2028.

NWPP System Summer Surplus Capacity

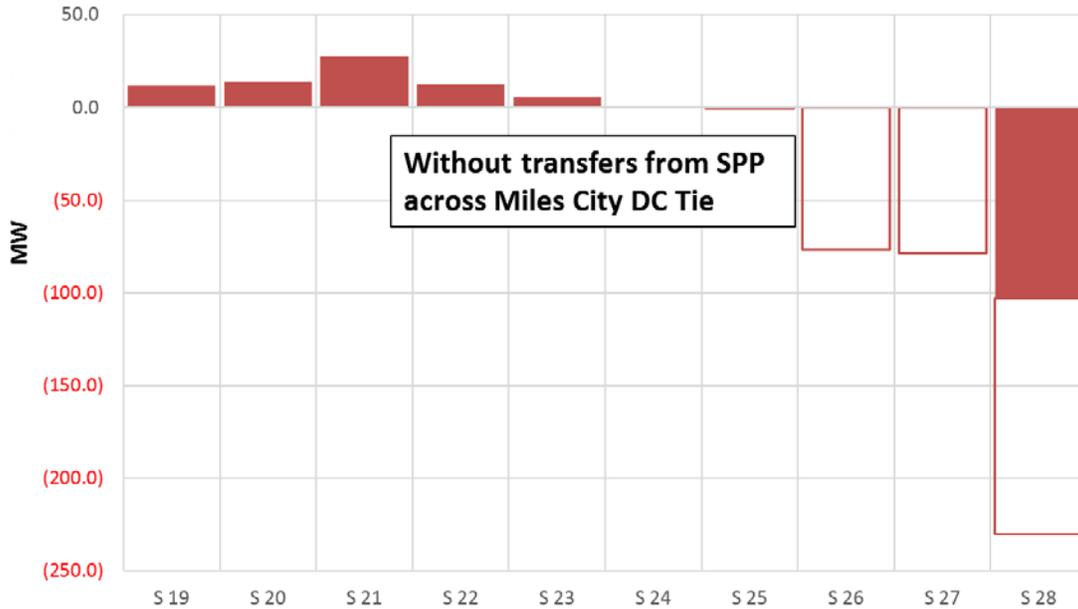


Figure 11-3 NWPP System Surplus Capacity with Current Recommended Bilateral Purchases

With the proposed bilateral purchases in the MISO LRZ 1 region, Basin Electric would not have to secure additional power supply for another two years, pushing the need out until 2025 instead of 2023.

MISO Zone 1 System Summer Surplus Capacity

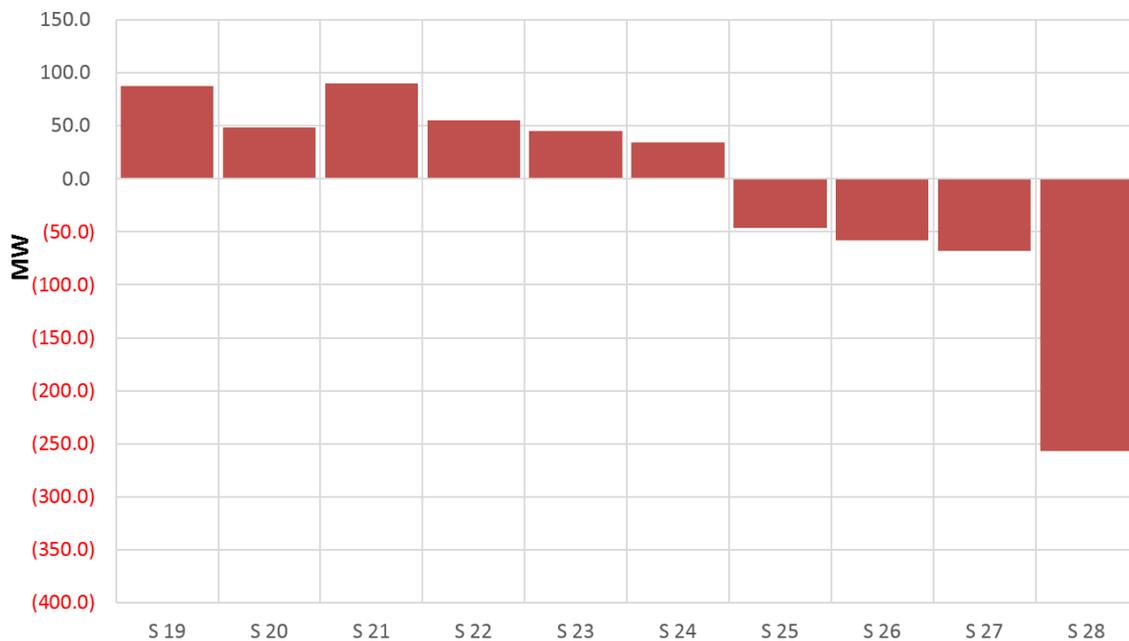


Figure 11-4 MISO LRZ 1 System Surplus Capacity with Current Recommended Bilateral Purchases

With the proposed bilateral purchases in the SPP region, Basin Electric could potentially push the need for additional power supply out another year to 2022, however there is still a pretty near-term need for more power supply resources than what is currently being proposed. Additional power supply options are still being analyzed as well as potential changes in load growth within the Williston Basin.

SPP System Summer Surplus Capacity

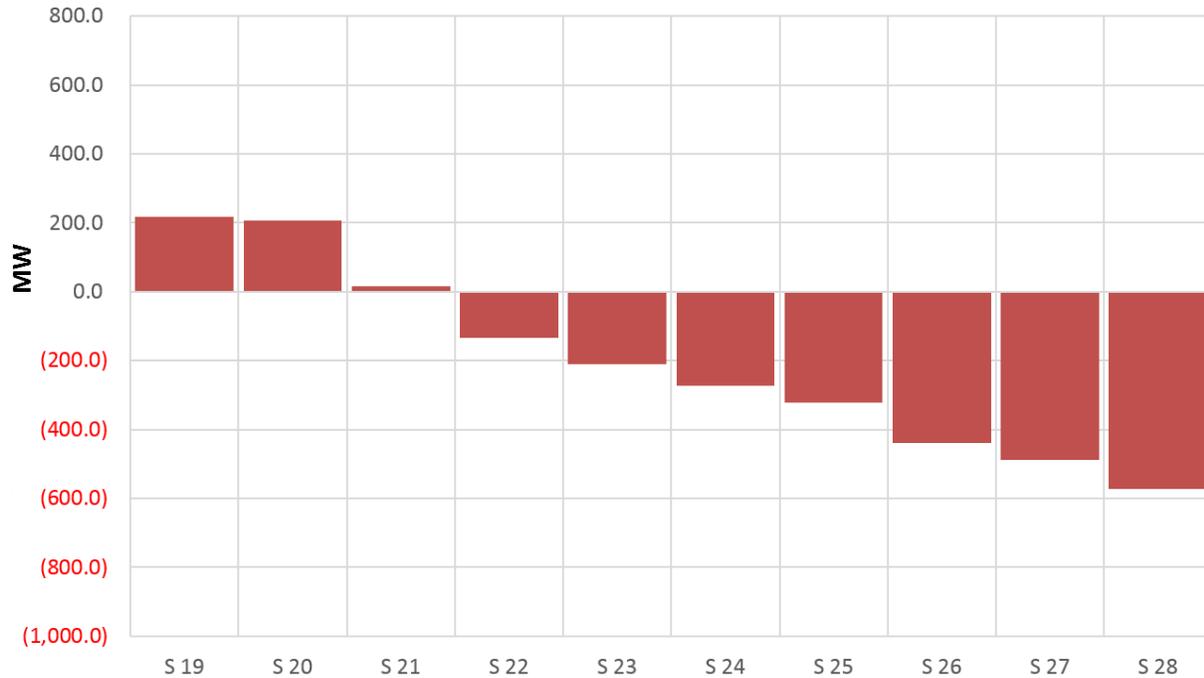


Figure 11-5 SPP System Surplus Capacity with Current Recommended Resource Expansion Plan

As mentioned at the end of Chapter 10) Risks and Uncertainties, Basin Electric plans to try securing bi-lateral contracts in an attempt to create a power supply cliff event in the 2026-2028 time period to economically align the new resource timing with the market and our members load growth. At this time Basin Electric is continuing to work on solutions that support this strategy, yet continue to monitor market conditions, load growth, and the regional reserve margins that will directly impact the viability and economics of this strategy.

5 Year Action Plan

On the basis of these conclusions, and in order to ensure Basin Electric has adequate power supply available to meet our member's needs the following 5-year action plan will be implemented:

1. Monitor load growth - Uncertainty in various sectors such as coal and oil could cause additional impacts to Basin Electric's current forecasted projections.
2. Secure proposed bilateral purchases. Continue to monitor additional available low cost power supply options while Reserve Margins in the power supply planning regions exceed the minimum requirements and products are available.
3. Continue to work on developing and expanding upon energy conservation and efficiency within the Basin Electric service territory.
4. Increase Basin Electric's near term reliance on the energy markets while natural gas prices are low and the market is long energy, and as wind continues to develop over the next couple of years, while still being able to protect us from the exposure of the market by having an appropriate backstop of natural gas fueled generation.
5. Continue to evaluate additional alternatives to move surplus power from our system in the western interconnection to our system in the Southwest Power Pool to more appropriately align our portfolios in the various planning areas.
6. Continue to evaluate additional low cost renewable options to provide additional energy to meet member power requirements.
7. Continue to evaluate extending Basin Electric's Firm Electric Service Contract with Western for Firm Peaking Power Service beyond 2020.
8. Continue to work with the membership to support member electric marketing programs with a number of special rates.

12) Appendix A - Acronyms and Abbreviations

| | |
|------------------|--|
| AC | Alternating Current |
| AES | Alternative Evaluation Study |
| AVS | Antelope Valley Station |
| Basin Electric | Basin Electric Power Cooperative |
| Biopower | Biomass Power |
| Black Hills | Black Hills Power & Light Association |
| BPA | Bonneville Power Administration |
| Btu | British Thermal Units |
| Capital Electric | Capital Electric Cooperative |
| CBM | Coal Bed Methane |
| Central Montana | Central Montana Electric Power Cooperative |
| Central Power | Central Power Electric Cooperative |
| CGS | Culbertson Generation Station |
| CO | Carbon Monoxide |
| CO ₂ | Carbon Dioxide |
| Corn Belt | Corn Belt Power Cooperative |
| CRN | Cooperative Research Network |
| Crow Wing | Crow Wing Cooperative Power & Light Company |
| CTG | Combustion Turbine Generators |
| CUS | Black Hills/Basin Electric/PRECorp Common Use System |
| DC | Direct Current |
| DCS | Deer Creek Station |
| DOE | U.S. Department of Energy |
| DFS | Dry Fork Station |
| DSM | Demand-side Management |
| East River | East River Electric Power Cooperative |
| EERE | U.S. DOE Energy Efficiency and Renewable Energy |
| EPRI | Electric Power Research Institute |
| ERC | Energy Resource Conservation |
| FAPRI | Food and Agricultural Policy Research Institute |
| Flathead | Flathead Electric Cooperative |

| | |
|-----------------------|--|
| FPL | Florida Power & Light Energy |
| GGS | Groton Generation Station |
| Grand | Grand Electric Cooperative |
| GWh | Gigawatt-Hours (1,000,000,000 watt-hours) |
| G&T | Generation and Transmission |
| HP/IP | High Pressure and Intermediate Pressure |
| Hydropower | Hydroelectric Power |
| IS | Integrated System |
| KEM | KEM Electric Cooperative |
| kW | Kilowatts (1,000 watts) |
| kWh | Kilowatt-Hours (1,000 watts-hours) |
| L&O | L&O Power Cooperative |
| LOS | Leland Olds Station |
| LRS | Laramie River Station |
| MAIN | Mid-America Interconnected Network, Inc. |
| MAPP | Mid-Continent Area Power Pool |
| MBPP | Missouri Basin Power Project |
| MCP | Market Clearing Price |
| Miles City Tie | Miles City Direct Current Tie |
| MEC | Mid-American Energy Company |
| Minnesota Valley CL&P | Minnesota Valley Cooperative Light & Power Association |
| Minnesota Valley EC | Minnesota Valley Electric Cooperative |
| MISO | Midwest Independent Transmission System Operator |
| MMBtu | Million British Thermal Units |
| Mor-Gran-Sou | Mor-Gran-Sou Electric Cooperative |
| MRO | Midwest Reliability Organization |
| MSA | Metropolitan Statistical Area |
| MW | Megawatts (1,000,000 watts) |
| MWh | Megawatt-Hours (1,000,000 watts-hours) |
| NEI | Nuclear Energy Institute |
| NERC | North American Electric Reliability Corporation |
| NDEX | North Dakota Export Constraint |

| | |
|-----------------|---|
| NIPCO | Northwest Iowa Power Cooperative |
| NOAA | National Oceanic and Atmospheric Administration |
| NPPD | Nebraska Public Power District |
| NPV | Net Present Value |
| NRECA | National Rural Electric Cooperative Association |
| NSP | Northern States Power (now, Xcel Energy) |
| NWPP | Northwest Power Pool |
| NYMEX | New York Mercantile Exchange |
| Roughrider | Roughrider Electric Cooperative |
| OTP | Otter Tail Power Company |
| O&M | Operating and Maintenance |
| PAC | PacificCorp |
| Pace Global | Pace Global Energy Services |
| PRB | Powder River Basin |
| PRECorp | Powder River Energy Corporation |
| PSA | Power Supply Analysis |
| PSCo | Public Service Company of Colorado |
| PVRR | Present Value Revenue Requirements |
| Rapid City Tie | Rapid City DC Tie |
| REA | Rural Electrification Administration |
| REC | Rural Electric Cooperative |
| REG | Recovered Energy Generation |
| RFP | Request for Proposal |
| RMPA | Rocky Mountain Power Area |
| Rosebud | Rosebud Electric Cooperative |
| REO | Renewable Energy Objective |
| RUS | Rural Utilities Service |
| Rushmore | Rushmore Electric Power Cooperative |
| SCADA | Supervisory Control and Data Acquisition |
| SMS | Spirit Mound Station |
| SO ₂ | Sulfur Dioxide |
| Stegall Tie | Stegall DC Tie |

| | |
|-----------------|--|
| TLR | Transmission Line Loading Relief |
| TOT | Total Flow on a specific grouping of transmission lines |
| Tri-State | Tri-State Generation and Transmission Association |
| Upper Missouri | Upper Missouri Generation and Transmission Electric Cooperative |
| URGE | Uniform Rating of Generating Equipment |
| USDA | United States Department of Agriculture |
| U.S. DOE EIA | United States Department of Energy: Energy Information Administration |
| U.S. DOE NREL | United States. Department of Energy National Renewable Energy Laboratory |
| U.S. EPA | United States Environmental Protection Agency |
| W&P | Woods and Poole Economics, Inc. |
| WB | Williston Basin |
| WECC | Western Electricity Coordinating Council |
| WECC-RMPA | Western Electricity Coordinating Council – Rocky Mountain Power Area |
| Western | Western Area Power Administration |
| WMPA | Wyoming Municipal Power Agency |
| Wright Hennepin | Wright Hennepin Cooperative Electric Association |
| WTI | West Texas Intermediate |

13) Appendix B - Model Description

Aurora by EPIS

The Aurora model is a price forecasting and analysis software based on the fundamentals of the competitive electric market. Aurora applies economic principles and dispatch simulation to model the relationships of supply, transmission, and demand for electric energy to forecast market prices. The operation of existing and future resources are based on forecasts of key fundamental drivers such as demand, fuel prices, hydro conditions, and operating characteristics of new resources. Algorithms are used in core dispatch, unit-commitment, pool pricing logic, and in the long-term capacity expansion capability. These algorithms simulate the non-linear electrical system and how resources such as hydro, supply-side and demand-side operate to serve load. Multiple electricity markets, zones, hubs and operating pools can be modeled.

Framework

Aurora's core pricing algorithms operate in an analytical framework that will help you understand the effect of changes in the key price drivers.

- Perform deterministic studies by changing the key assumptions in the input tables
- Perform scenario analysis using change sets to modify assumptions for each scenarios without altering the underlying database. Change sets can be run individually or combined together.
- Perform Monte Carlo studies using exogenous, or endogenous, or use Latin Hypercube.

Nodal Capability

Integrated into Aurora is the capability to perform locational marginal price (LMP) forecasts and FTR analyses. This internal capability uses nodal level data and an optimal power flow (OPF) solution to determine locational marginal pricing. The priority in development was on quality price forecasts, agile use and the speed of processing large volume nodal data.

Extensible Architecture

Aurora is a memory-based architecture written in visual basic.net and the user interface is designed to be used by energy modelers.

- The Aurora interface is easy to navigate
- Input assumptions can reside in the Aurora input database, or linked from SQL server or Microsoft Excel workbooks, and can be manipulated using the computational datasets.
- Aurora simulation options controls and logic settings enable you to quickly specify relevant modeling elements.

Change Sets

Change sets provide the ability to create and save multiple sets of input database changes within a single Aurora project. They are a convenient and efficient way to set up and run sensitivity studies or scenario

analyses beyond a base case set of assumptions. Change sets provide a more efficient way to manage the variation in assumptions associated with scenario analyses.

Output

After the modeling run is finished the outputs can be looked at in detail to see the scenarios/cases results. You can study monthly/annual startups, fuel price, contract MWh, load, sales, transfers, capacity, peak demand, output capability and many other scenarios.

Pivot tables can be custom built to find specific information on a zone, time, condition, loss, area link, or many other variables. You can also build custom pivot tables and save them as a quick view to open quickly to view the common areas, or conditions you frequently look at.

14) Appendix C - Works Cited

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