

NORTHWESTERN ENERGY
2019 ELECTRICITY SUPPLY RESOURCE
PROCUREMENT PLAN

Volume 1 -- Table of contents

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CHAPTER 1

EXECUTIVE SUMMARY

Montana’s energy landscape is evolving, changing from a state that produces more electricity than our citizens can use 24x7, 365 days a year, to a state where there is a growing risk there won’t be enough electricity to serve our citizens at critical times of peak load. A similar situation is occurring throughout the Pacific Northwest – a key source for NorthWestern’s market purchases. The NorthWestern Energy Electricity Supply Resource Procurement Plan addresses this critical risk and outlines how the company’s Montana customers’ energy needs will be met with reliable energy at the lowest cost.

Reductions in regional and in-state coal generation are limiting the ability of Montana to import and export energy, and growth in customer energy demand across the Pacific Northwest means the energy available from the market will be less certain at key times and prices will be more volatile. NorthWestern Energy has been reducing our customers’ exposure to the market by developing a portfolio that includes hydro, natural gas, coal, wind, and solar generation. However, in order to manage the increasing risk to our customers and continue providing them with reliable energy, NorthWestern Energy must work quickly to reduce our customers’ exposure to power markets, especially for certain types of power products. To just assume the market will always be able to provide customers with sufficient electricity at affordable prices is a reckless approach that could have severe reliability and cost consequences.

OUR CUSTOMERS' MAJOR RISK IS NOT HAVING SUFFICIENT ENERGY WHEN THEY NEED IT MOST.

- ◀ NorthWestern Energy's current peak requirement (the amount of electricity needed to service all customers at the times of highest demand plus planning reserve margins) is about 1,400 megawatts (MW). This is 645 MW more than the peak capability of NorthWestern's current portfolio.
- ◀ Planned regional retirement of 3,600 MW of coal-fired generation will cause regional peak energy shortages as early as 2021.
 - ◀ Due to planned Montana coal generation retirements (and potential unplanned retirements), critical transmission capacity and access to other states' power markets will be limited.
 - ◀ NorthWestern is planning to join the Western Energy Imbalance Market (EIM) in 2021 which will bring many benefits to our customers. However, this will require NorthWestern to control sufficient supply to meet hourly loads – including peak loads.
 - ◀ Regional discussions are currently underway to build upon the EIM and develop a more fully organized market which will require NorthWestern to control the full amount of peak energy to serve demand, plus a reserve margin.

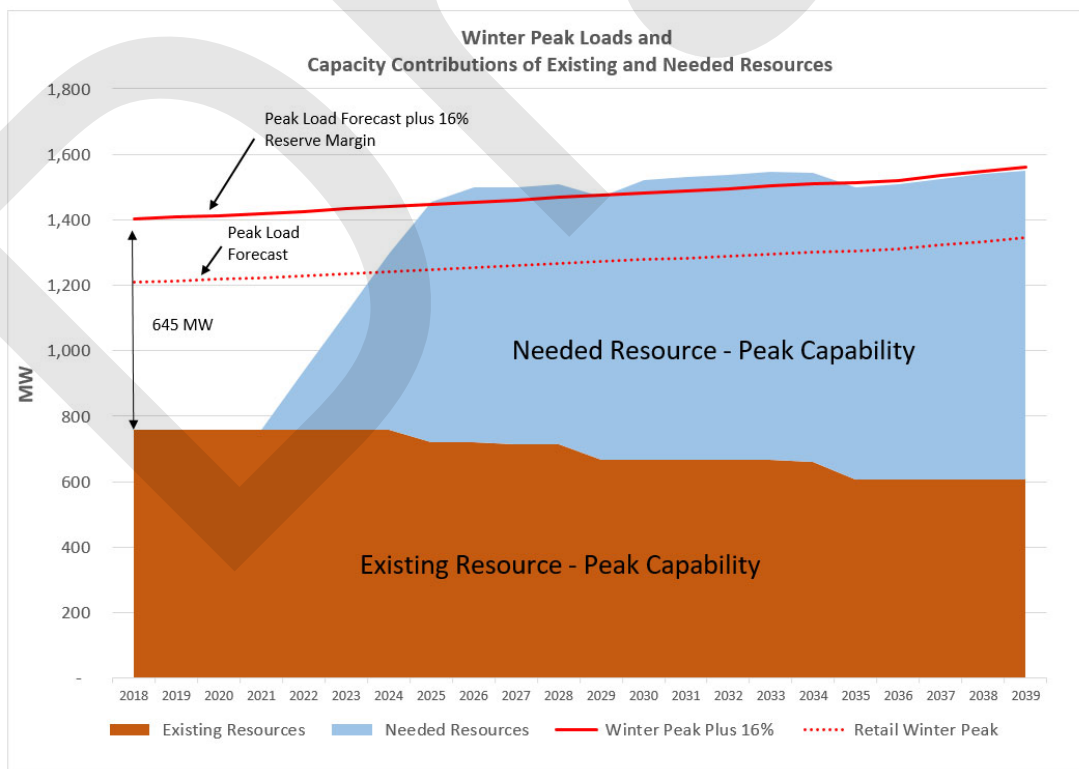
The Colstrip Transmission System was designed to primarily export energy, but it is also used to import energy from out-of-state sources, especially during critical times. Due to its designed purpose, under many circumstances the Colstrip Transmission System may not be adequate to import energy from markets outside of Montana to replace the power used in Montana that is generated now at the Colstrip units.

Planning For the Future

Capacity Needs

NorthWestern Energy’s current resources provide about 755 MW of peaking capacity, which is the energy available during periods of our customers’ highest demand. An additional 645 MW of peaking capacity must currently be purchased from the market to meet our needs. Without new peaking capacity, the market exposure will increase to about 725 MW by 2025 (including reserve margins). This peaking need assumes continued development of cost-effective demand side management (conservation) and small distributed generators (net-metering). Meeting peak load with market purchases means being exposed to the market at the worst possible time – when the market is volatile and prices are high.

Figure 1-1. Peaking Capacity Needs



NorthWestern Energy’s customers require the most energy during times of extreme high or extreme cold temperatures. Fast, dispatchable generation resources are needed to provide reliable service to our customers during these times of high demand. Wind generation is low during these periods due to the low or nonexistent winds associated with high pressure systems accompanying temperature extremes. Solar generation contributes to summer peak loads but provides no significant contribution to address winter peak loads, which occur after sunset.

Flexible Capacity Needs

NorthWestern’s customers need resources capable of providing more than just energy and peaking capacity. NorthWestern’s resource portfolio generally generates enough energy to serve average load, but is significantly short both peaking and flexible capacity. Resources that can be dispatched on-demand to ramp up or shut down relatively quickly are identified as flexible capacity. Flexible capacity is needed to match generation to short-term variations in load. Additionally, variable energy resources like wind and solar require dispatchable energy resources to balance the energy grid and assure reliability. NorthWestern Energy’s current levels of flexible capacity resources are adequate for the existing resource portfolio, but will fall short following the current planned (and future unplanned) additions of wind and solar resources. *(Unplanned additions come mainly through “Qualifying Facilities” that our customers are required to purchase by law.)*

Energy Needs

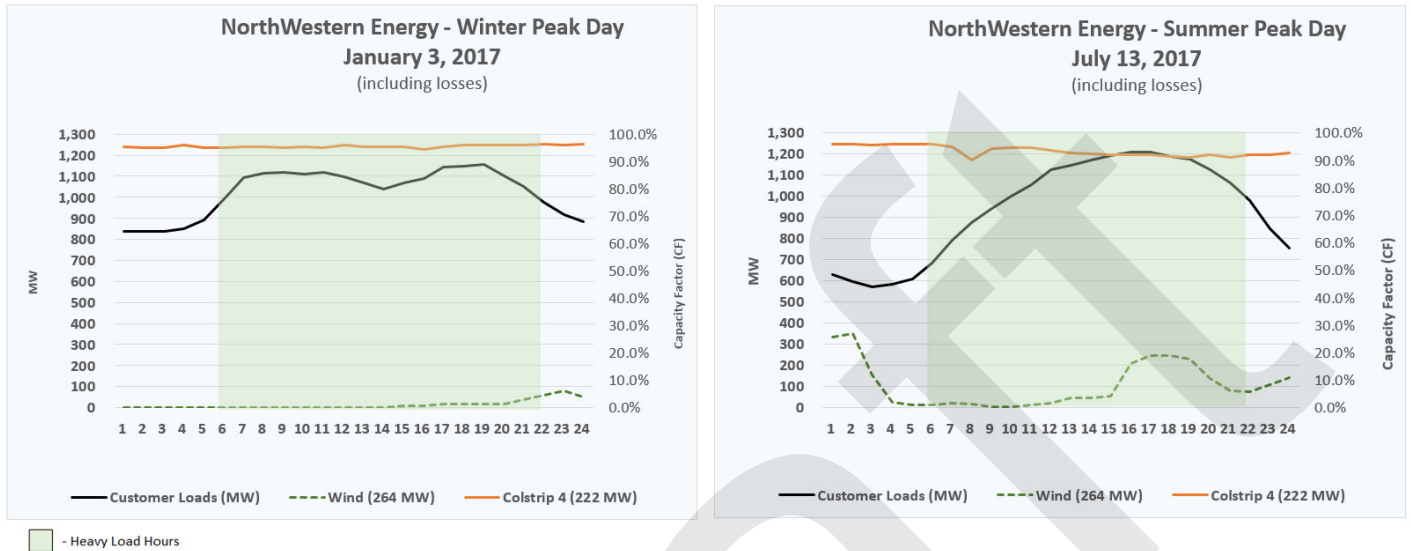
While NorthWestern Energy is in need of resources to supply our customers during periods of their highest demand, our current portfolio is much better off when looking at customers’ average energy needs. The type of products generation resources can produce is critical to ensure the specific needs of the portfolio are met without having to acquire excess

generation. During heavy load hours, the current resource portfolio produces a little less energy (on a monthly basis) than customers consume. During light load hours, the portfolio produces more energy (on a monthly basis) than customers consume. Excess energy is sold into the wholesale electricity market at lower prices, often lower than the cost of the energy being produced. This is done because NorthWestern must take the energy from variable resources like wind even if it is not needed, and the hydro and thermal resources like Colstrip have minimum production levels or must be operating in order to respond to changes in wind generation or loads.

Wind and solar are capable of providing low-cost energy but are generally not available to provide capacity when customers need it most, like after sunset on the coldest winter days in December and January. The Winter and Summer peak load days of 2017 (January 3rd and July 13th) are shown in Figure 1-2 below. The black line represents customer load - shown as MW on the left hand scale. The dashed green line shows wind production (from the 364 MW of wind that we have to serve customers) as percentage of its nameplate capacity on the right hand scale. The orange line represents Colstrip 4 production, also shown as a percentage of its nameplate capacity on the right hand scale. NorthWestern has seen this pattern repeatedly since 2017, most recently during a cold spell occurring during the week of February 4th, 2019.

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Figure 1-2. 2017 Peak Load Days

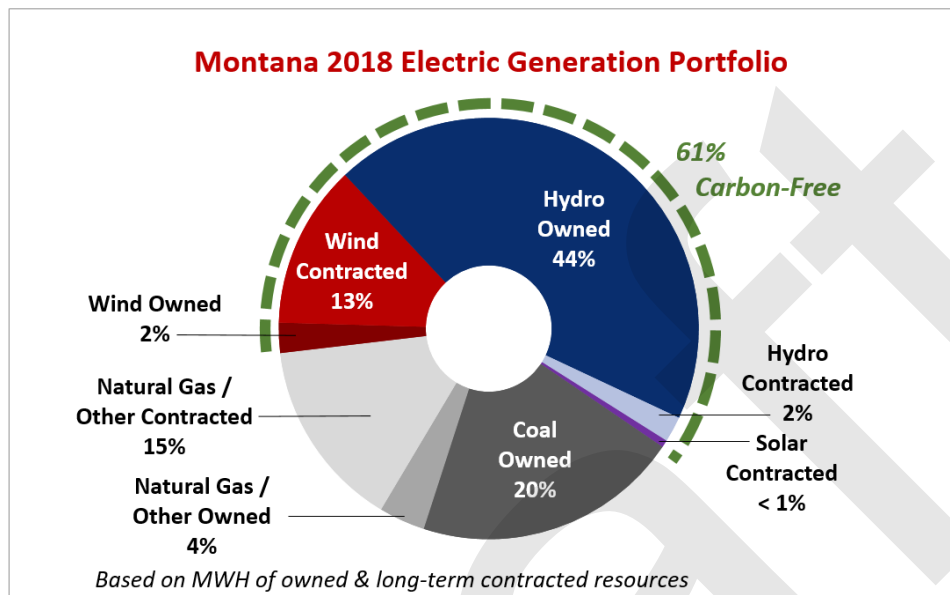


As illustrated above, wind contributed very little of its maximum generation capability (especially on the critical winter peak day), while Colstrip 4 generated at 90 to 95 percent of its maximum capability. During peak load periods, customers need resources that NorthWestern can call upon as needed, 24 hours a day, 7 days a week.

Carbon Emissions

NorthWestern Energy purchased 11 hydroelectric facilities in 2014 with a current generating capacity of 448 MW (with potential for future upgrades). The hydroelectric system is primarily a run-of-the-river system which provides a large part of the backbone of our generation portfolio, contributes significantly to our low cost carbon-free energy production, and provides system reliability for our customers. In 2018 NorthWestern’s energy portfolio was 61% carbon free energy.

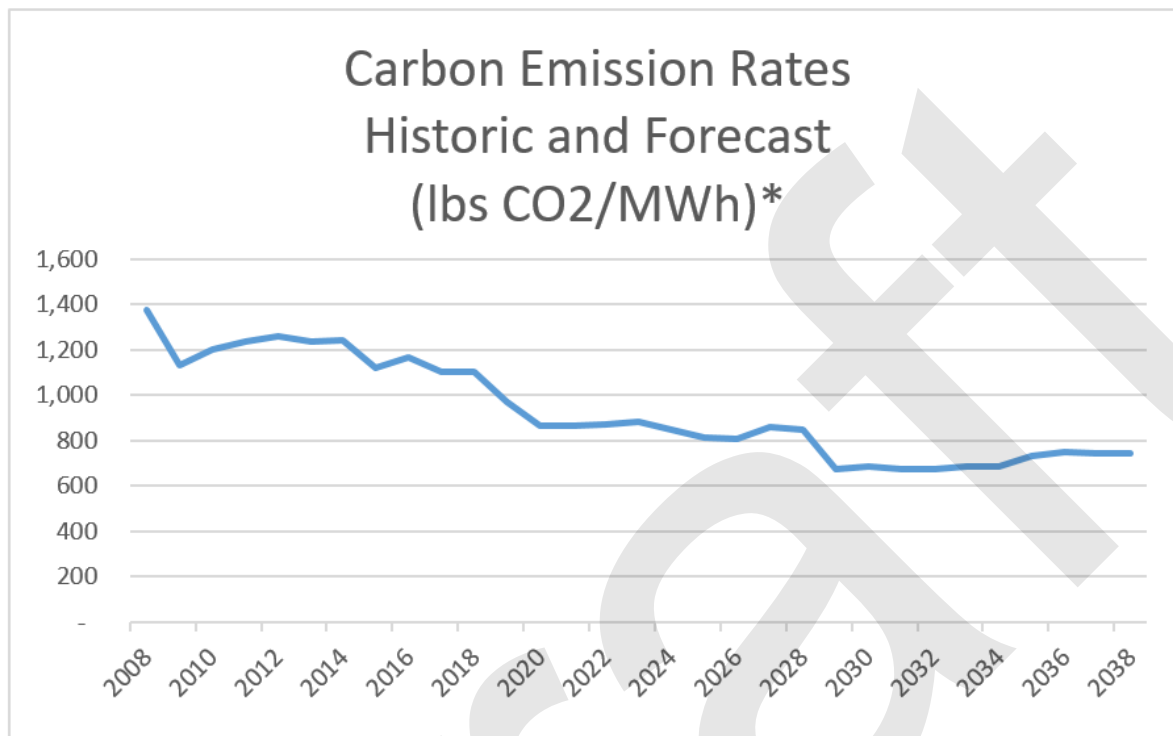
Figure 1-3. Percent of 2018 Electric Generation Portfolio



With the help of Montana’s generation portfolio, NorthWestern continues to be one of the leaders in the industry for carbon free portfolios. Carbon dioxide emissions associated with NorthWestern’s Montana portfolio have been significantly less than nearly all of our peers.

From 2008 to 2018 carbon dioxide emissions associated with NorthWestern’s resource portfolio have declined, and they are forecast to continue to decline. Resource opportunities, technology improvements, and technology cost reductions could also reduce emissions. As shown in Figure 1-4, carbon emissions associated with the Base portfolio decline over the term of the plan. Significant declines occur when Colstrip Energy Limited Partnership (CELP) and Yellowstone Energy Partnership (YELP) leave the portfolio. Together, CELP and YELP provide about 11% of the energy in our portfolio but contribute about 37% of the carbon dioxide emissions.

Figure 1-4. Historic and Future Carbon Emissions



* 2018 Estimated pending EPA final data. Forecast derived from Base portfolio

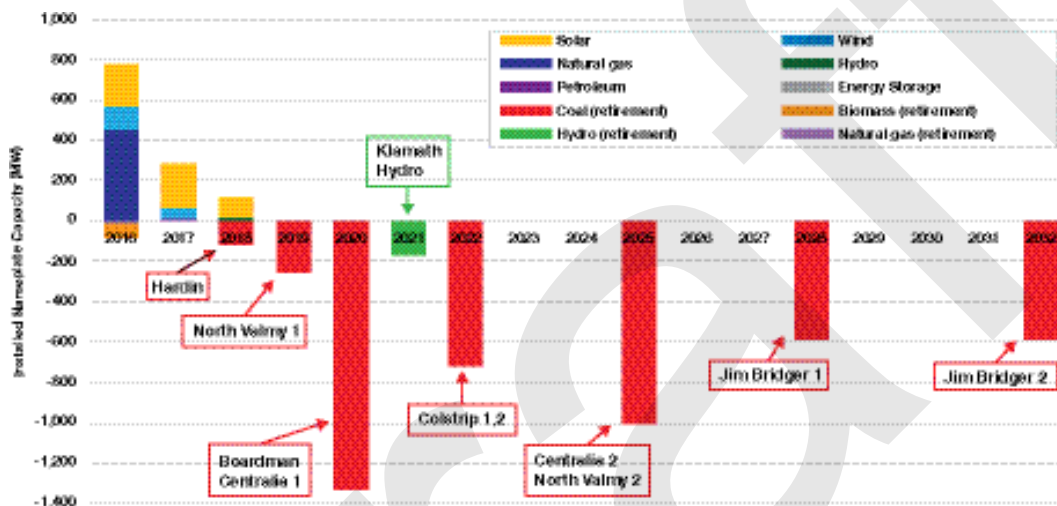
From 2008 to 2018 carbon dioxide emissions associated with NorthWestern’s resource portfolio have declined, and are forecast to continue to decline (Base portfolio shown above).

State and Regional Coal Retirements

Planned retirements in the Pacific Northwest region exceed 3,600 MW and the Northwest Power and Conservation Council forecasts regional capacity shortfalls as early as 2021. NorthWestern Energy’s continued reliance on the market to purchase energy to fill the gap during peak customer demand will significantly increase price and reliability risk to NorthWestern Energy’s customers because of the reduced energy supply availability. Future technological advances will help mitigate this risk, but NorthWestern Energy has

an ongoing obligation to plan for affordable and reliable resources. The measured multi-year approach NorthWestern proposes will allow for the incorporation of advancements in generation technology and potential costs declines.

Figure 1-5. NWPCC Planned Plant Retirements



Source: Northwest Power and Conservation Council, Draft 7th Plan Mid-Term Assessment

Transmission Constraints

Transmission capacity is necessary for market access in order to purchase (import) and sell (export) power. During the most critical periods, NorthWestern Energy relies heavily on imports into our system in order to meet customer needs. The transmission system in Montana was constructed around, and is heavily reliant on, the generating resources and their location, including the entire Colstrip Power Plant. Retirement of Colstrip units will impact NorthWestern Energy’s ability to import sufficient power to meet peak energy demand. As discussed earlier, the transmission lines at Colstrip are limited for the import of energy because they are designed to export energy. Another concern is that if no additional generation is built to justify keeping the current Colstrip transmission lines,

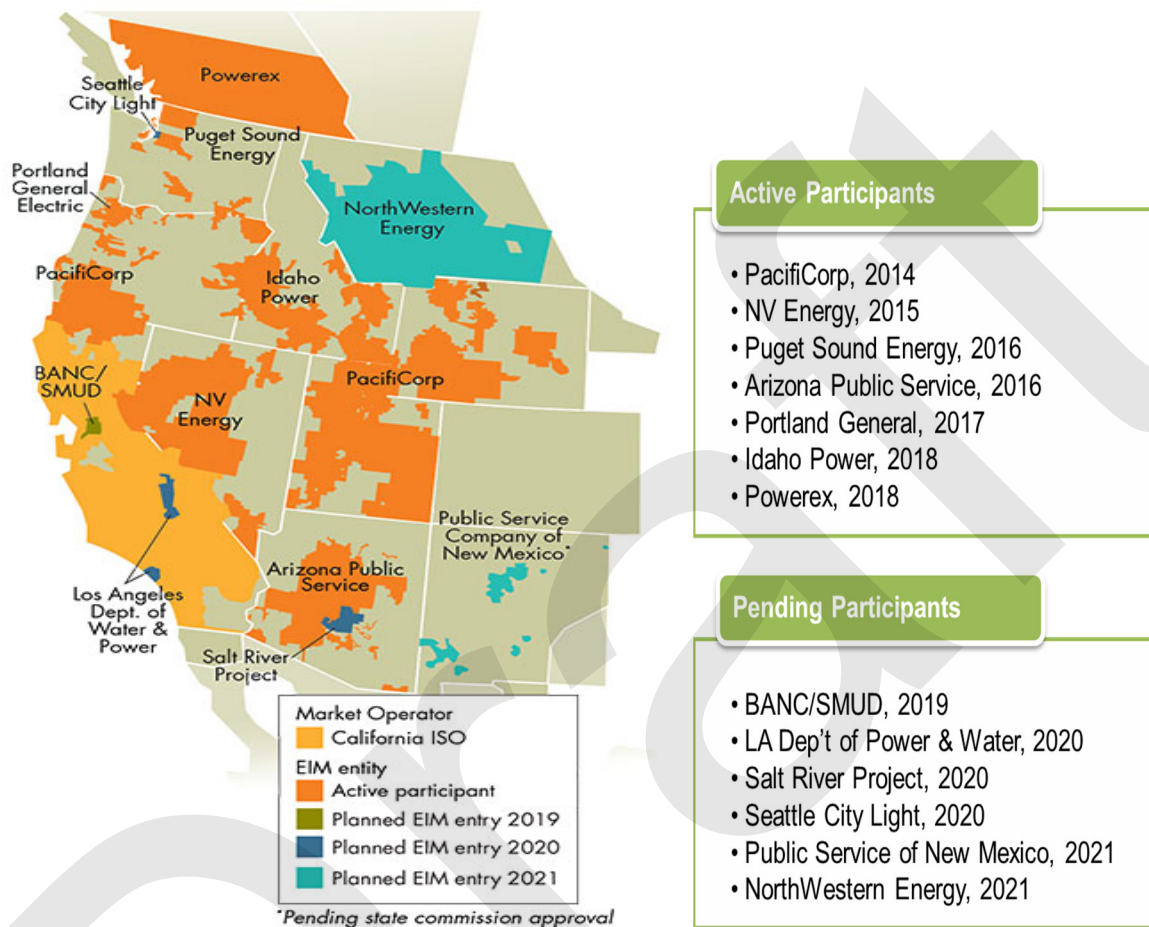
those lines could also be retired, which will contribute to bottlenecks in the remaining energy transmission system used in Montana to serve NorthWestern Energy customers.

Integrating Our Grid and Markets

A significant event affecting NorthWestern’s 2019 Resource Procurement Plan process was the decision by NorthWestern to join the EIM. On November 8, 2018, NorthWestern announced our intent to enter the Western EIM in the spring of 2021. With NorthWestern’s execution of an Implementation Agreement, the total number of active and pending participants in the Western EIM now totals 14 utilities serving 80 percent of customer loads within the US portion of the WECC. Additionally, Bonneville Power Administration is currently undertaking a stakeholder process to consider EIM entry, and could join as early as 2022.

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Figure 1-6. EIM Active and Pending Participants



Regional Transmission Organization (RTO)

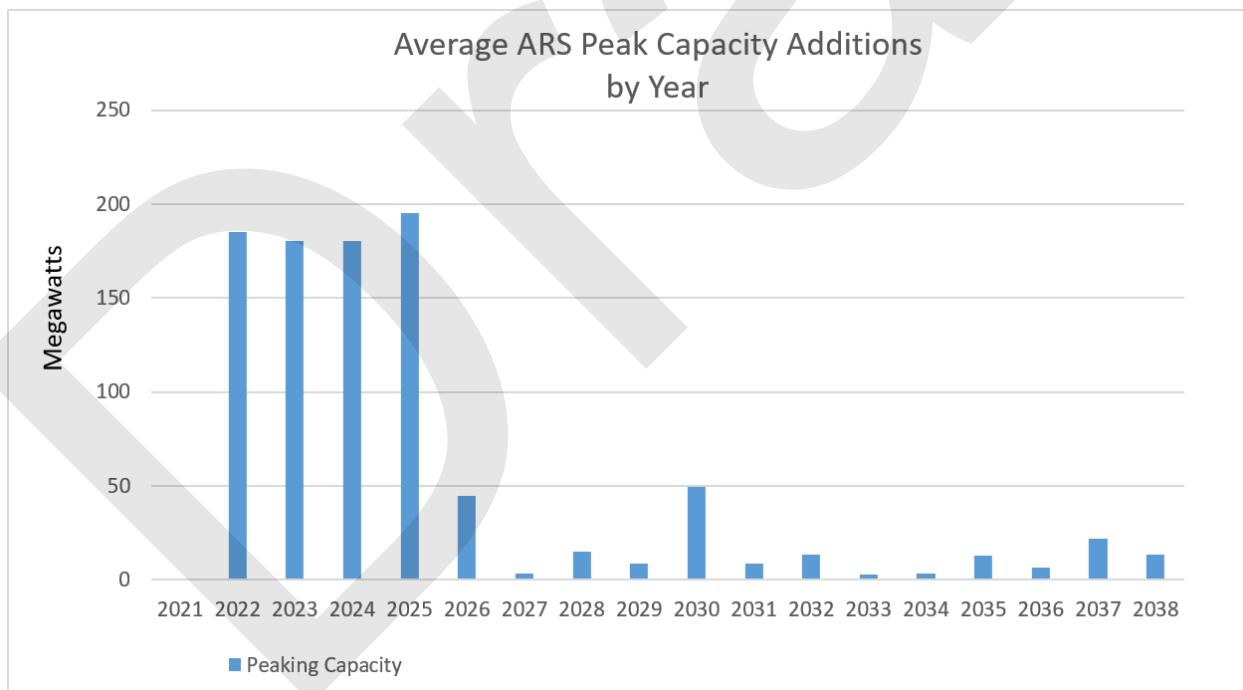
In early 2018, the California Independent System Operator (ISO) began a process to enhance the day-ahead market within the full Independent System Operators footprint (the EDAM initiative). The enhancements to CAISO’s day-ahead market are targeted to go live in 2019 with a platform that will allow the addition of a day-ahead market to the Western EIM. The extension of the day-ahead market to EIM participants, if supported by EIM members and CAISO, could go live as early as 2022. The next step to a full RTO or ISO typically follows quickly. NorthWestern Energy assumes for the purposes of the 2019

Resource Procurement Plan that EIM entry will occur in 2021, followed by EDAM entry in 2022 and full RTO/ISO entry in 2025.

Resource Portfolios

NorthWestern’s resource plan shows the results of thirteen “future” resource portfolios. Each portfolio satisfies our peak capacity needs by adding resources that achieve resource adequacy by 2025 and maintain resource adequacy throughout the plan period. The graph below shows average peak capacity additions by year for all portfolios using automatic resource selection (ARS) to achieve a 16 percent reserve margin by 2025.

Figure 1-7. Peaking Capacity Additions by Year



The portfolios identify resources with known costs and indicate that thermal resources provide the best value (lowest cost) to meet our customers’ future needs for peak capacity.

Renewable resources and energy storage technologies are projected to continue to decline in cost, but are still more expensive than natural gas fired resources, and were not selected by the model. A portfolio which meets our customers' future resource needs without the addition of any new carbon producing resources would lower carbon emissions, but at a cost. Meeting our customers' future needs by adding carbon free resources is projected to cost \$523,000,000 more than meeting their needs using natural gas fired resources. Moving to a 100% carbon free portfolio was not modeled, but a recent regional analysis indicates that it would be cost prohibitive.¹

While our portfolio modeling shows that natural gas resources provide the lowest cost portfolio, competitive solicitations open to a wide variety of technologies will be used to determine which resources will ultimately serve our customers' needs as identified in this Plan at lowest cost.

Strategy in Action

In order to have adequate energy supplies to meet peak load requirements by 2025, NorthWestern Energy will solicit competitive proposals from a variety of resources and will also consider opportunity resource purchases. The model used to evaluate resources in this plan will also be used to evaluate resources submitted in competitive solicitations or opportunity resources. Opportunity resources consist of existing resources that become available for purchase and cannot be known or modeled in advance (the purchase of the hydroelectric system is a good example of an opportunity resource).

NorthWestern will use a staged multi-year approach to add up to 200 MW of capacity per

¹ Resource Adequacy in the Pacific Northwest study to be released March 2019 by Energy + Environmental Economics (E3).

year from 2022 to 2025. NorthWestern Energy will evaluate all resources which can meet the portfolios’ needs, including renewable and thermal based generation, power purchase agreements, and owned energy resources comprised of different structures, terms, and technologies with the long term objective of a lowest cost, stable, and reliable energy portfolio. The staged approach allows for incremental steps through time with opportunities for different resource types and new technologies while also building a reliable portfolio to meet local and regional conditions while minimizing customer impacts.

Table 1-1. RFP Resource Acquisition Goals

RFP Date	RFP Amount	Online Date	Remaining 2025 Need
			725 MW
2019	Up to 200 MW	2022	525 MW
2020	Up to 200 MW	2023	325 MW
2021	Up to 200 MW	2024	125
2022	Up to 200 MW	2025	0

In the past, NorthWestern has updated its Electricity Supply Plan every two years, involving a technical advisory committee with third party facilitators and multiple public meetings. An incremental approach to generation acquisition is also consistent with this planning cycle. NorthWestern is considering whether maintaining the technical advisory committee is the best means of incorporating the public into the planning process.

NorthWestern Energy will consider all opportunity resources and solicit competitive proposals to meet customers’ future energy resource needs. NorthWestern Energy will use an independent evaluator to conduct a proposal solicitation process open to all resources (including “demand side” resources) for up to 200 MW of peaking capacity in 2019, which is about one-fourth of NorthWestern Energy’s projected need in 2025. This process will be repeated in subsequent years to provide a resource-adequate energy portfolio. The proposal solicitation process will consider a wide variety of resource options, resource sizing, ownership options and contract lengths.

CHAPTER 2

PLANNING PROCESS AND HISTORY

NorthWestern Resource Planning Process and History

Montana Planning Requirements

The electricity supply resource planning process followed by NorthWestern complies with Montana Code Annotated (MCA) Title 69, Chapter 8, Part 4 (MCA 69-8) and Administrative Rules of Montana (ARM) Title 38, Chapter 5, Subchapter 82 (ARM 38.5.82: Default Electric Supplier Procurement Guidelines or “guidelines”). MCA 69-8-419 requires NorthWestern to plan for future electricity supply resource needs, manage a portfolio of electricity supply resources, and procure new electricity supply resources when needed while pursuing the following objectives:

- Provide adequate and reliable electricity supply service at the lowest long-term total cost;
- Conduct an efficient electricity supply resource planning and procurement process that evaluates the full range of cost effective electricity supply and demand side management options;
- Identify and cost effectively manage and mitigate risks related to its obligation to provide electricity supply service;
- Use open, fair, and competitive procurement processes whenever possible; and,
- Provide electricity supply service and related services at just and reasonable rates.

The guidelines “do not impose specific resource procurement processes or mandate particular resource acquisitions. Instead, the guidelines describe a process framework for considering resource needs and suggest optimal ways of meeting those needs.”

NorthWestern has historically submitted biennial plans under these provisions every odd numbered year. In its comments on NorthWestern’s 2015 Plan, the Montana Public Service Commission (MPSC) indicated NorthWestern should file the next plan, which is this one, by December 15, 2018. On November 13, 2018, NorthWestern filed a Motion for Extension to file the 2019 Electricity Supply Resource Procurement Plan (2019 Plan), requesting an extension until February 15, 2019. On December 5, 2018, the MPSC issued a Notice of Commission Action which granted an extension of the deadline, with the following conditions:

- NorthWestern must file a draft plan for public review by March 15, 2019;
- Stakeholders must be given 60 days to provide comment on the draft plan;
- The final plan must contain a section which explains how NorthWestern considered and addressed public comments; and,
- NorthWestern must file a final resource plan after the public comment period, but before December 15, 2019.

NorthWestern Resource Planning – Historical Context

NorthWestern’s 2013 Plan

Shortly before submitting the 2013 Plan, NorthWestern announced an agreement to purchase the hydro assets of PPL Montana, LLC (referred to as the “hydro acquisition”). This was an “opportunity acquisition” as envisioned in our 2011 Plan. The 2013 Plan identified a portfolio with the hydro resources as having the lowest expected long-term cost relative to portfolios comprised of market transactions and combined cycle (natural gas) generation.

The 2013 Plan also recognized the potential for future imbalances between regional loads and resources due to the announced closures of several coal plants and plans by other utilities in the region to rely more heavily on market purchases to serve their loads. The potential for such regional imbalances continues to contribute to the Northwest Power and Conservation Council's (NWPPCC) concerns about the adequacy of the regional power supply (these concerns are discussed in further detail below). The hydro acquisition significantly reduced NorthWestern's reliance on the market and exposure of supply costs to market price volatility, which increased NorthWestern's cost certainty and rate stability. The hydro acquisition marked an important step in NorthWestern's transition out of the planning paradigm that resulted from Montana's period of energy deregulation, during which time NorthWestern's predecessor divested itself of all generation assets.

NorthWestern's 2015 Plan

In our 2015 Plan (submitted to the MPSC in March of 2016), NorthWestern included analyses of the potential needs for additional capacity to address the large imbalance between projected peak loads and the maximum generation possible from the portfolio of owned and contracted resources. Despite NorthWestern's acquisition of the Hydros and other resources over the preceding ten years, peak loads still significantly exceeded NorthWestern's resource capacity. NorthWestern has historically overcome this imbalance through hourly market purchases of firm energy that replaced capacity. The 2015 Plan focused on the long-term uncertainty associated with over reliance on market transactions and the reliability concerns from assuming there will always be sufficient depth in the wholesale energy market to meet NorthWestern's capacity requirements. Regional supply conditions were undergoing fundamental changes (and still are) due to substantial additions of intermittent wind and solar resources, hydrologic flow restrictions, and planned retirements of coal resources which were (and are) anticipated to contribute to the increasing inadequacy of the regional supply portfolio (this is discussed below).

NorthWestern's capacity needs were also increasing as a result of new operating requirements, in particular the Reliability Based Control (RBC) standards required by the North American Electric Reliability Corporation (NERC).

As with the 2013 Plan, NorthWestern used the PowerSimm modeling software to analyze the performance of the energy supply portfolio and potential new resources across a wide range of possible future conditions. The model identified a portfolio comprised of dispatchable flexible generating capacity capable of providing ancillary services¹, load-following, and serving peak demand as the Economically Optimal Portfolio. The model also evaluated whether wind and solar photovoltaic (PV) resources could contribute to meeting NorthWestern's winter peak capacity demand and found neither resource to be a cost-effective alternative to gas-fired generation options because wind and solar are unable to serve as dispatchable resources and have low (wind) or zero (solar) capacity contributions during periods of peak winter loads.

MPSC Comments on the 2015 Plan

In its comments on the 2015 Plan,² the MPSC stated that the action items were generally reasonable but that NorthWestern should pursue a rigorous stakeholder process to validate the conclusions of the 2015 Plan rather than proceed directly with requesting proposals for a new flexible capacity resource³. The MPSC questioned the reasonableness of the

¹ Ancillary services are those necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system and include: providing increases (INC) or decreases (DEC) in output on short notice; spinning and non-spinning contingency reserves; and, frequency response.

² The MPSC's complete comments on NorthWestern's 2015 Plan are available at <http://psc2.mt.gov/Docs/ElectronicDocuments/getDocumentsInfo.asp?docketId=11712&do=false>

³ The MPSC's comments came 11 days prior to the release of a competitive solicitation for resources

economically optimal portfolio and identified five main concerns it had with the 2015 Plan. A general overview of these concerns is provided below, followed by a description of NorthWestern’s efforts to address the MPSC’s concerns in the 2019 Plan.

1. The MPSC stated its primary concern with the 2015 Plan was that the resource adequacy constraint imposed in NorthWestern’s portfolio analyses was not sufficiently justified and no support was offered for the proposed rate of acquiring capacity. The MPSC stated NorthWestern’s resource adequacy should be measured by comparing NorthWestern’s peak retail load position to the regional or interconnection peak demand accounting for import limitations. The MPSC also inferred that NorthWestern’s objective of meeting “minimal resource adequacy” by 2021 appeared to refer to a portfolio of physical resources equal to retail peak load (rather than relying on market transactions). In its explanations of these concerns, the MPSC also requested that NorthWestern be more clear and precise in discussions of different types of capacity, and that NorthWestern make a determination of the base capacity capability of its current portfolio.
2. The MPSC expressed the concern that the resource alternatives NorthWestern evaluated in the 2015 Plan fell short of “the full range of cost effective supply and demand-side management options” as required in MCA § 69-8-419.
3. The MPSC stated the 2015 Plan did not sufficiently consider multiple sources of uncertainties that NorthWestern and customers may face in the future, including uncertainty in resource costs, capacity contributions and integration requirements for wind and solar resources, implications of transitioning to RBC standards, load forecasts and impacts of behind-the-meter distributed generation (including seasonality, capacity value, and energy production), natural gas price forecasts, carbon regulation, infrastructure costs (electric and natural gas), participation in the

EIM and associated impacts on the liquidity of energy and capacity markets, and the development of a regional ISO or RTO.

4. The MPSC stated the stakeholder process used in developing the 2015 Plan was insufficient and NorthWestern should pursue a rigorous stakeholder process to validate the conclusions in the 2015 Plan, including more frequent contact with Electric Technical Advisory Committee (ETAC), more timely provision of meeting materials, more information about NorthWestern’s modeling and analyses, and greater representation of viewpoints on ETAC.
5. The MPSC stated the 2015 Plan did not demonstrate how a subsequent resource procurement process would be open, fair, and competitive and expressed that any requirements for minimum service periods ought to be well-justified and not exclude short-term options such as those potentially provided by existing resources. The MPSC also stated the owners of long-lived resources should bear some of the risk in the later years of such resources’ lives that the performance of the resource differs, relative to market prices, from expectations.

NorthWestern Response to MPSC Comments

Following are descriptions how NorthWestern’s 2019 Plan, and 2019 resource planning process, address the concerns raised in the MPSC’s comments.

1. NorthWestern’s 2019 Plan includes an analysis of the coincidence of NorthWestern’s peak load hours with the region’s peak load hours⁴. Additionally, the 2019 Plan discusses the continuing work of NWPCC on regional resource adequacy.

⁴ Region in this context is the geographic area of concern for the NWPCC.

Concerning the Commission’s comments that “minimal resource adequacy” by 2021 appeared to refer to a portfolio of physical resources, the comment comes from a misunderstanding of the 2015 Plan. The Commission should have been aware that NorthWestern planned to meet “minimal resource adequacy” through a competitive solicitation of proposals from a wide variety of resources under a wide variety of ownership positions.⁵

The MPSC asked NorthWestern to be more precise in our discussion of the different types of capacity that generation resources may provide and requested that NorthWestern determine the capacity capabilities of our existing resource portfolio. The 2019 Plan defines the various capacity attributes of our existing resource portfolio, identifies the capacity needs of our customers, identifies the capacity needs required to integrate additional variable energy resources into NorthWestern’s resource portfolio, and identifies the peaking resources that NorthWestern will need to control as wholesale energy markets evolve.

2. NorthWestern did not analyze an expanded list of resource costs in the 2015 Plan because a very wide array of resource options were given an equal footing to compete in the 2017 flexible capacity RFP. In response to Commission comments, NorthWestern expanded the number of resource options for consideration in the 2019 Plan and retained HDR Engineering, Inc. (HDR) to analyze the costs and

⁵ The 2015 Plan was filed on March 31, 2016. The Flexible capacity request-for-proposals (RFP) was discussed with ETAC at a meeting held on November 10, 2016. The MPSC is a member of ETAC. The MPSC issued its comments on February 2, 2017; NorthWestern issued its Competitive solicitation on February 13, 2017 (after a 30-day public comment period on the draft RFP). The RFP is provided in Volume 2, Chapter 1.

performance of a wide variety of new build resource options. HDR also conducted a request for interest (“RFI”) to identify existing resources (also known as opportunity resources) for potential inclusion in the 2019 Plan analysis.⁶

3. The MPSC’s comments identified a number of risk variables NorthWestern did not sufficiently address in the 2015 Plan. In some instances, issues could not have been addressed during the timing of the 2015 Plan due to lack of information. Following is the list of risk issues raised by the MPSC along with a discussion of how these risks are addressed in the 2019 Plan.

- **Resource Costs:** HDR provided cost and performance characteristics for a wide variety of resource options, and also conducted an RFI. NorthWestern will conduct an RFP process to acquire our customers’ future resource needs. The RFP process will provide the best available resource information and costs, far surpassing NorthWestern’s “snapshot in time” analysis.
- **Capacity contributions and integration of wind and solar:** NorthWestern’s transmission group conducted a variable energy resource (VER) study to identify resource requirements for additional wind and solar generation.
- **Transition to RBC:** A study to address the transition to RBC was not performed for the 2015 plan because the data did not exist and implementation of RBC was compulsory. RBC test period operations started in March of 2016 and full implementation didn’t occur until July of 2016. RBC data was used in the VER Study mentioned above.
- **Net metering impacts:** NorthWestern retained Navigant to conduct an economic analysis and evaluation of solar PV net energy metering (NEM)

⁶ The RFI is provided in Volume 2, Chapter 1.

costs and benefits in Montana and to submit the study to the MPSC before April 1, 2018. The Navigant NEM study is explained in more detail in Chapter 3.

4. NorthWestern conducted a rigorous stakeholder process for the 2019 Plan. We believe the participation of ETAC, the public and several supporting studies have helped foster a greater understanding of the needs of our retail customers, the various types of resources and the current and anticipated state of the markets. Following are some highlights of the stakeholder process.

- NorthWestern retained a moderator for ETAC meetings to guide meetings and encourage input from ETAC members.
- The number of ETAC meetings increased from five for the 2015 Plan, to eighteen for this plan.
- Four PowerSimm modeling workshops were held for the benefit of ETAC members.
- Three public meetings were held prior to the release of the draft plan for public comment.
- ETAC and the public were given 60 days to provide comments on the draft plan

NorthWestern Resource Planning – Regional Context

The Pacific Northwest has historically had a surplus of generating capacity. However, recent studies question the ability of the regional power supply to meet future capacity needs. In the broader regional context of the Pacific Northwest, NorthWestern is a relatively small player whose peak retail loads of around 1,200 MW amount to less than 4 percent of the regional peak, which has recently reached nearly 35,000 MW. Additionally,

relative to other investor-owned utilities in the region, NorthWestern serves a much smaller share of its retail load with utility-owned resources. The remainder of this section discusses these factors in more detail.

Regional Resource Adequacy

The most recent assessment of the adequacy of the regional power supply in the Pacific Northwest is from the NWPCC dated June 14, 2018 and entitled “Pacific Northwest Power Supply Adequacy Assessment for 2023”.⁷

Executive Summary – Pacific Northwest Power Supply Adequacy Assessment for 2023

Accounting for existing resources, planned resources that are sited and licensed, and the implementation of the NWPCC’s energy efficiency targets, the Northwest power supply is likely to become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants (1,330 MW combined). The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent, which exceeds the NWPCC’s standard of 5 percent.

By 2022 the LOLP is projected to rise to about 7 percent, due to the additional retirements of the North Valmy 1 coal plant, the Colstrip 1 and 2 coal plants and the Pasco gas-fired plant (479 MW combined). In 2023 the LOLP is expected to remain at about 7 percent. The increase in LOLP would be higher except for the NWPCC’s targeted energy efficiency savings and savings from codes and federal standards. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 MW in 2021 with an additional need for 300 to 400 MW in 2022.

⁷ Pacific Northwest Power Supply Adequacy Assessment for 2023. NWPCC, June 14, 2018, available at <https://www.nwccouncil.org/reports/pacific-northwest-power-supply-adequacy-assessment-2023>.

It should be noted that this analysis examines the adequacy of the aggregate regional power supply. Individual utilities within the Northwest have varying resource mixes and loads and, therefore, have varying needs for new resources. In aggregate, Northwest utilities have identified 540 MW of wind, about 800 MW of (unspecified fuel source) capacity and other small resources that could be developed by 2021, if needed. These planned resources are not included in this assessment because they are not sited and licensed. Also excluded from this analysis are approximately 400 MW of demand response, which is the remaining part of the 600 MW identified in the NWPCC's Seventh Power Plan as likely being available by 2021. While the NWPCC believes this level of demand response will be available, it is not included in this analysis because of ongoing concerns regarding barriers to its acquisition.

While it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could significantly alter the outcome. For example, the results provided above are based on medium load growth. Reducing the 2023 load forecast by 2 percent results in an LOLP of just under 5 percent and has roughly the same effect as adding 650 MW of capacity. Increasing the load forecast by 2 percent raises the 2023 LOLP to about 10 percent and almost doubles the amount of capacity needed (from 650 to 1,000 MW) to satisfy the NWPCC's 5 percent standard.

The reference case results assume a conservative level of available Southwest market supply. Increasing that supply by 500 MW lowers the 2023 LOLP to a little over 5 percent and only about 50 MW of additional capacity are needed to meet the NWPCC's 5 percent standard. However, decreasing the Southwest market supply by 500 MW raises the LOLP to 8.6 percent and would require 1,050 MW of additional capacity.

Reducing the load forecast by 2 percent and increasing the Southwest market availability by 500 MW lowers the LOLP to 3.5 percent and no additional capacity is required for adequacy. However, increasing the load forecast by 2 percent and decreasing the Southwest market by 500 MW raises the LOLP to 12 percent and requires about 1,500 MW of additional capacity to satisfy the NWPCC’s adequacy standard.⁸

The Relationship between NorthWestern’s and the Region’s Peak Loads

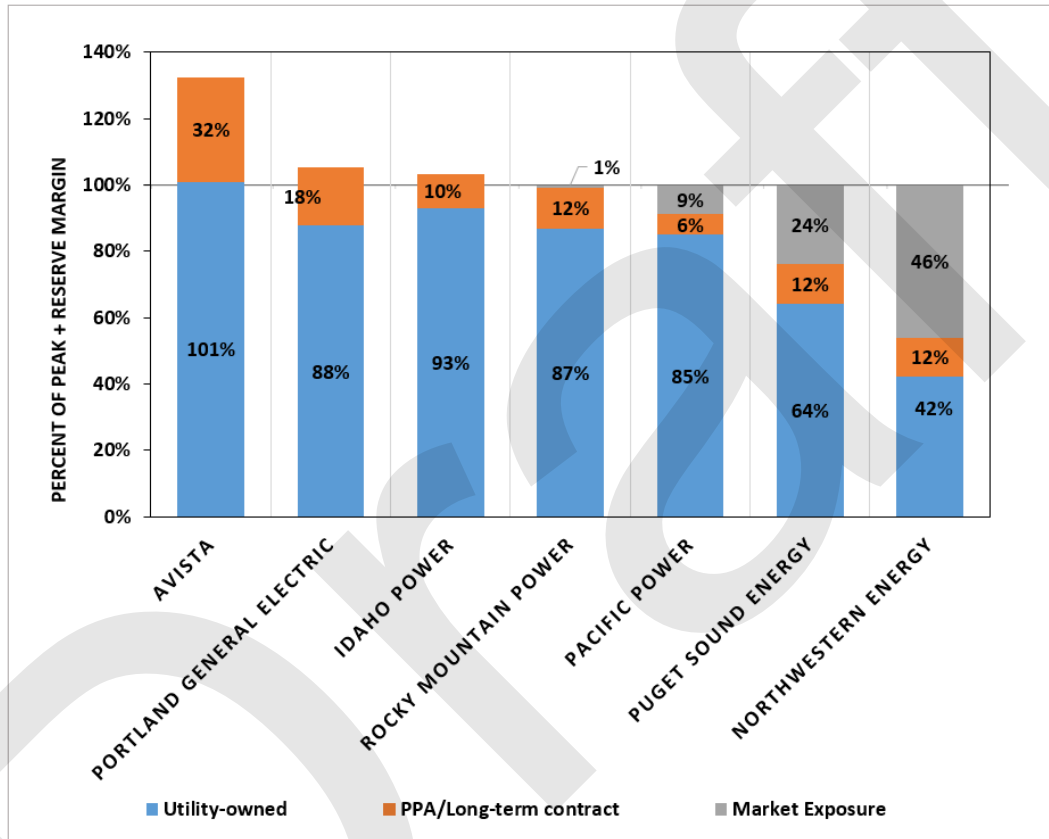
The NWPCC’s assessment predicts the region will have a capacity deficit in the next 3 to 4 years, though it notes there are a wide range of uncertainties that could lead to substantially different levels of regional adequacy. These uncertainties arise from the uncertainty in future regional loads, the level of imports that may be available from the Southwest market, and developments in energy efficiency and demand response. Additionally, the area considered in the NWPCC’s assessment extends to the continental divide and thus includes only a portion of NorthWestern’s balancing area. Furthermore, as the NWPCC explains, “individual utilities within the Northwest have varying resource mixes and loads and, therefore, have varying needs for new resources.”

Compared to other investor-owned utilities in the region, NorthWestern’s load to resource balance is the shortest. This means the generating capacity of NorthWestern’s resource portfolio relative to our peak load is smaller than any of the other utilities’ resource portfolios. Therefore, to meet peak load responsibilities, NorthWestern relies more heavily on short-term market purchases of hourly firm energy for its capacity than any of these

⁸ Executive summary from the Pacific Northwest Power Supply Adequacy Assessment for 2023. NWPCC, June 14, 2018, available at <https://www.nwccouncil.org/reports/pacific-northwest-power-supply-adequacy-assessment-2023>.

other utilities. See the following figure, which shows the current capacity positions for 7 investor-owned utilities in the Pacific Northwest.

Figure 2-1. Capacity Position as a Percentage of Peak Load + Planning Reserve Margin⁹



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⁹ Notes on Figure 2-1: This figure was constructed using data from each utility’s most recently available Integrated Resource Plan and reflects the year of data closest to the present (which was 2017 for some utilities and 2018 for others). The breakdown of utility-owned versus contracted resources is approximate because some utilities report some long-term contracts together with their utility-owned resources. Market exposure is calculated by adding each utility’s stated Planning Reserve Margin to its expected peak load and then subtracting from this its owned resources and PPAs/long-term contracts. NorthWestern’s is calculated with a 16 percent planning reserve margin (PRM), which is consistent with that used elsewhere in this plan for portfolio modeling and approximately equal to the 16.4 percent PRM assigned by NERC to the Pacific Northwest (WECC NWPP-US) in NERC’s 2017 Long-term Reliability Assessment.

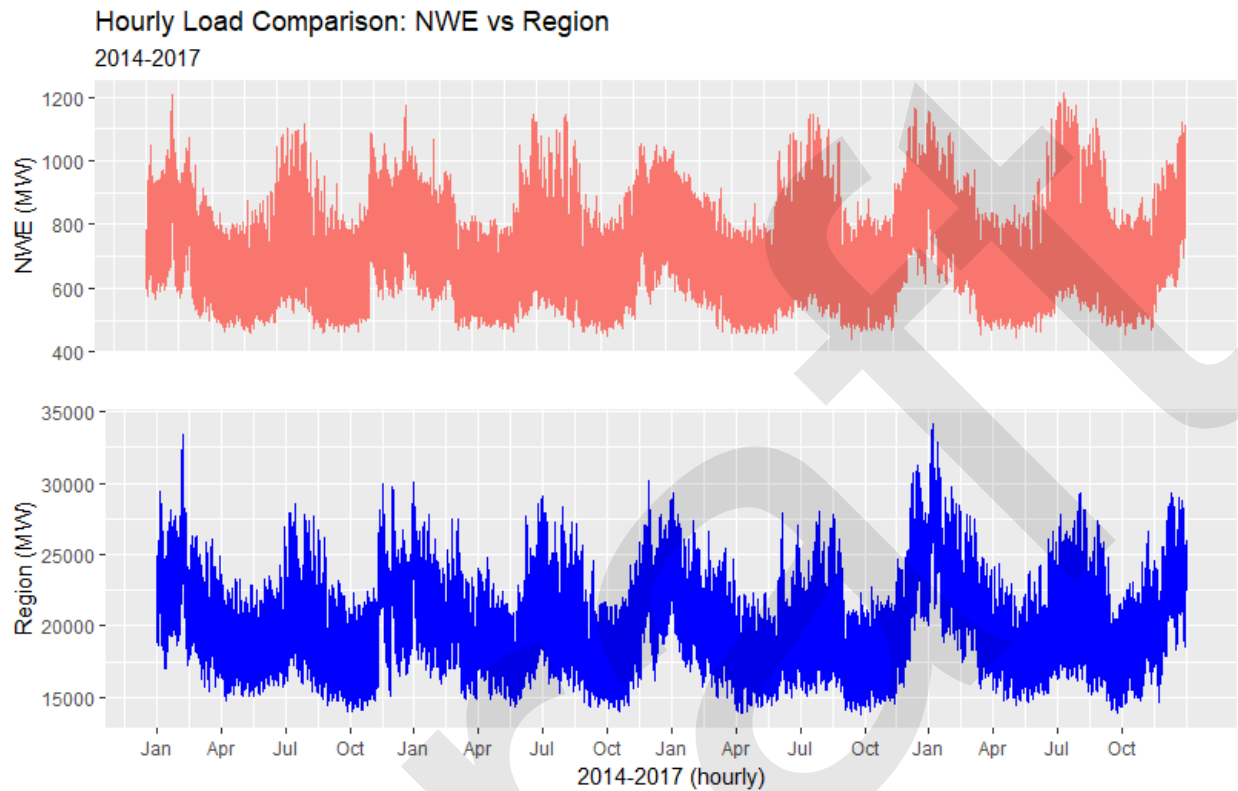
NorthWestern’s heavy reliance on the market is apparent not only when expressed as a percentage of peak load but in absolute terms as well. NorthWestern’s market exposure is approximately 645 MW. Compared to other utilities, even those much larger than NorthWestern, this is significant. For example, Pacific Power’s market exposure is only equal to about half of NorthWestern’s (330 MW vs 645 MW), even though Pacific Power’s peak load is 2.7 times greater. Rocky Mountain Power’s peak is five times larger than NorthWestern’s, yet their market exposure is 90 percent *less* than NorthWestern’s. Similar patterns also hold for Avista, Portland General Electric, and Idaho Power, who each have *larger loads* than NorthWestern but *less exposure to the market*.

NorthWestern’s load generally peaks during the same seasons and hours as the region. Like the region, NorthWestern has a winter-peaking load and the months identified by the NWPCC as the periods most likely to experience inadequacy—December, January, and February—correspond to NorthWestern’s times of greatest need.¹⁰ The similarities in the seasonal patterns between NorthWestern’s load and the regional load can be seen in the following figure.

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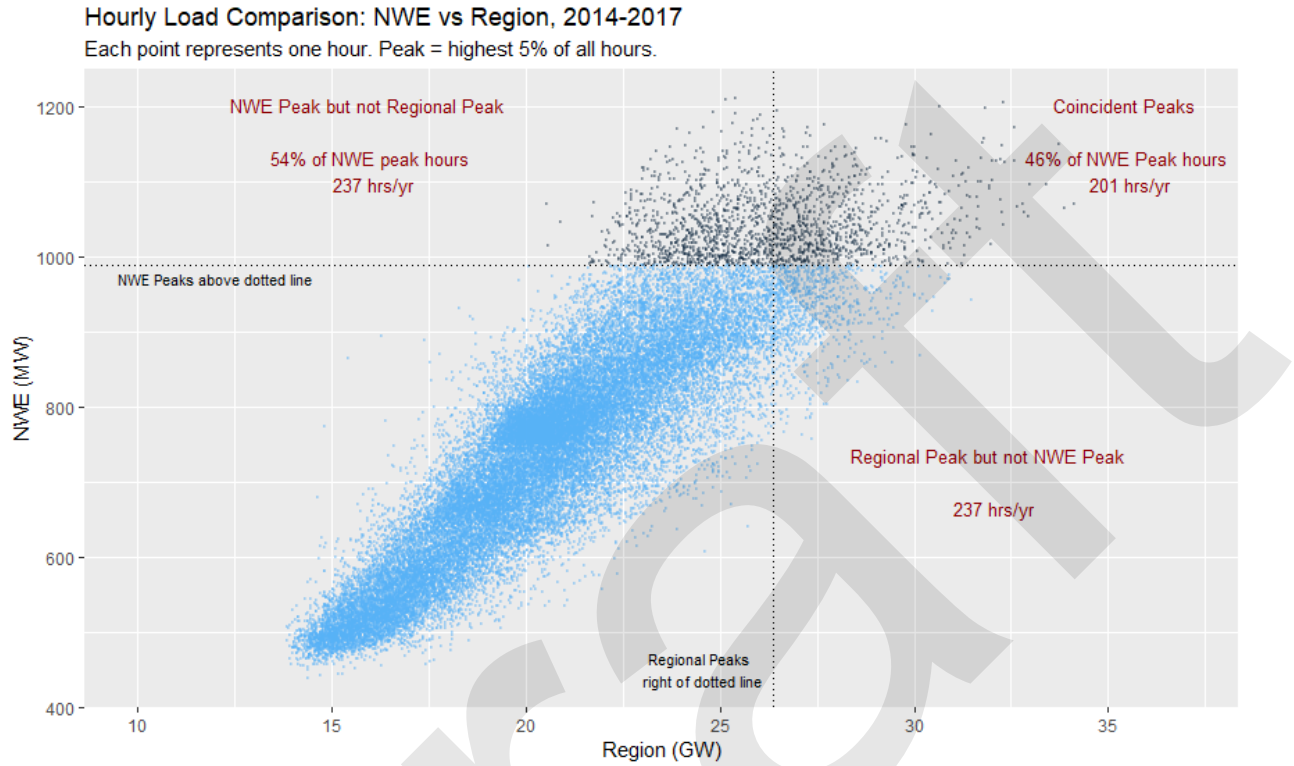
¹⁰ Pacific Northwest Power Supply Adequacy Assessment for 2023, page 13, Figure 1. NWPCC, June 14, 2018.

Figure 2-2. Hourly Loads: NorthWestern vs Regional



At an hourly level, NorthWestern’s load and the regional load are highly correlated (correlation coefficient of 0.89). The following graph shows this relationship. From 2014 to 2017, about half of the time when NorthWestern’s load was peaking (defined here as the top 5 percent of loads), the region was also peaking. Clearly, the coincidence of NorthWestern’s peak load hours to regional peak load hours means that NorthWestern should not continue to rely on the short term regional energy market to meet its future capacity needs.

Figure 2-3. NorthWestern vs. Pacific NW Load



CHAPTER 3

LOAD SERVICE REQUIREMENT

2018 Customer, Energy, and Peak Demand Forecasts

Energy Forecast

Overview and Background

NorthWestern has developed its customer, energy, and peak demand forecasts in a consistent manner for several planning cycles. The basis for the customer forecast is population within NorthWestern’s service territory, and the primary basis for the energy and peak demand forecasts are the customer forecast and normal weather forecast. Other than a few variations that have been interjected into the process from time to time, these components have and continue to serve as the explanatory variables in the linear regression models that produce the forecasts.

NorthWestern’s Demand Side Management (DSM) programs have been and continue to be incorporated into the energy and peak demand forecasts as well. Prior year DSM acquisition is inherent in the energy and peak demand regression results, while future DSM acquisition is forecasted and applied to the regression results to reflect both a “gross” and “net” of DSM value for the energy and peak demand forecasts. NorthWestern plans to acquire an average of 4 MW per year or over 78 average megawatts (MWa) in DSM energy savings between 2017 and 2036, excluding losses, with contributions to 2036 summer and winter peaks projected at 114 MW and 123 MW, respectively.

The impact of NEM is a variable introduced into the 2018 forecast. An NEM penetration study conducted by the National Renewable Energy Laboratory (NREL) on behalf of the MPSC and subsequently refined by Navigant to tailor to NorthWestern's distribution and transmission system, concluded that, barring any changes to existing tariffs in which NEM customers receive the full retail value for energy generated, installed capacity of NEM solar PV systems will grow from about 11 MW in 2017 to 270 MW in 2038. The result of this growth is over 40 MWa in energy and a contribution to the summer peak of 140 MW in 2038, excluding losses. Both the NREL study and the Navigant study can be found in Volume 2, Chapter 3.

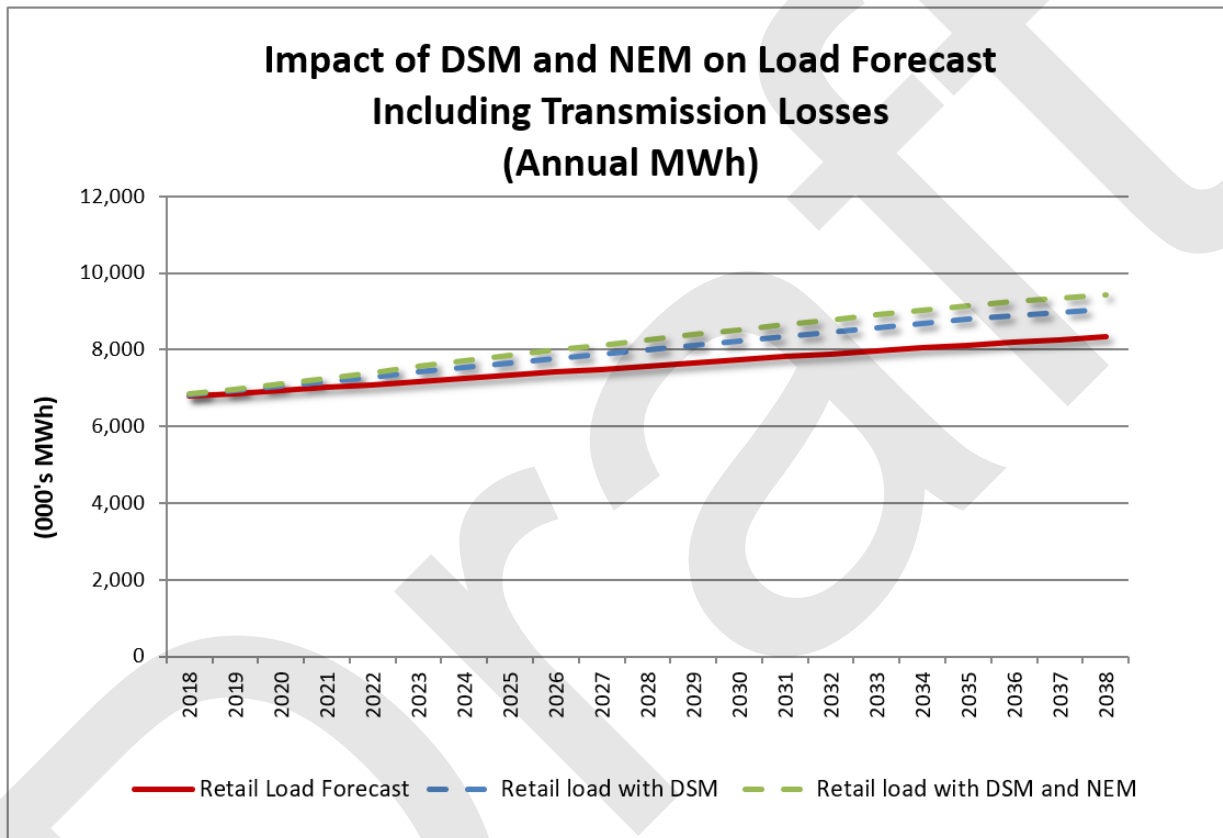
Methodology and Energy Forecast

The methods of estimating future energy usage are rate class specific. Residential and GS-1 Secondary usage combined represents approximately 85% of the total energy load-serving obligation so these forecasts are based on more detailed regression models using the specific customer-class forecast and normal weather, defined as the 10-year average historical total degree days (heating plus cooling), as the explanatory variables. Usage for all other customer classes is based on historical actual usage coupled with adjustments for known changes to future usage. In addition, transmission line losses are included in all customer classes' forecasts.

Expected DSM and NEM are also projected throughout the 20-year forecast period and subtracted from Residential and GS1-Secondary energy forecasts as well as the winter and summer peak forecasts. The projected DSM and NEM have a substantial impact on projected annual load; the forecasted average annual growth rate for the Default Supply load-serving obligation excluding future DSM and NEM is 1.0%, while the average annual growth rate when including future DSM and NEM is 0.4%. Figure 3-1 illustrates the impact of DSM and NEM on future energy usage. Historic DSM and NEM energy and

peak impacts are inherent in the regression results in that they are included in historic load figures, the basis for forecasting future loads.

Figure 3-1. Retail Load Forecast



The energy forecast including line losses, DSM, and Solar-PV NEM is presented in Table 3-1.

Table 3-1. Actual and Forecasted Default Supply Loads

Year	Default Supply (MWh)	Annual Growth Rate	Commercial (MWh)	Annual Growth Rate	Residential (MWh)	Annual Growth Rate	Other (MWh)	Annual Growth Rate
2000	5,624,145		2,987,179		2,149,361		487,606	
2005	5,980,373	1.2%	3,230,839	1.6%	2,244,640	0.9%	504,895	0.7%
2010	6,218,232	0.8%	3,401,472	1.0%	2,518,232	2.3%	298,528	-10.0%
2015	6,434,595	0.7%	3,454,868	0.3%	2,555,131	0.3%	424,597	7.3%
2020	6,758,899	1.0%	3,582,170	0.7%	2,743,708	1.4%	433,021	0.4%
2025	6,828,790	0.2%	3,607,169	0.1%	2,781,879	0.3%	439,742	0.3%
2030	6,942,619	0.3%	3,656,734	0.3%	2,846,143	0.5%	439,742	0.0%
2035	7,094,165	0.4%	3,743,862	0.5%	2,910,562	0.4%	439,742	0.0%
20-YR CAGR		0.4%		0.5%		0.4%		1.2%

Note: Includes losses, DSM, and Solar PV-NEM

Customer Forecast

Residential and GS-1 Secondary (small commercial) customers make up 85% of NorthWestern Energy’s load serving obligation but they make up 98% of the company’s electric customers. The primary driver of the customer forecast is the projected population in NorthWestern’s service territory, which is comprised of 37 of Montana’s 56 counties. For the 2018 customer forecast, NorthWestern used an econometric population forecast developed by Woods & Poole Economics, Inc. The forecast is constructed using an independent econometric model and provides county population projections through 2050. As shown in Table 3-2, actual and expected population growth for the state of Montana and NorthWestern’s service territory is about the same; approximately 0.9%. Total Accounts are projected to grow at about a 1.2% annual rate, higher than the population growth rate because of total new connects in residential single and multi-family housing units and commercial buildings.

Table 3-2. Actual and Forecasted Population and Customers

Year	Montana Population	Annual Growth Rate	NWE Service Territory Population	Annual Growth Rate	NWE Total Accounts	Annual Growth Rate	NWE Residential Accounts	Annual Growth Rate	NWE GS1-Secondary Accounts	Annual Growth Rate
2000	903,773		705,765		292,437		235,784		49,759	
2005	940,102	0.8%	734,415	0.8%	315,755	1.5%	253,124	1.4%	55,491	2.2%
2010	990,507	1.1%	774,998	1.1%	338,804	1.4%	270,571	1.3%	60,872	1.9%
2015	1,028,317	0.8%	805,975	0.8%	359,565	1.2%	287,387	1.2%	64,554	1.2%
2020	1,080,979	1.0%	844,416	0.9%	383,698	1.3%	306,290	1.3%	69,643	1.5%
2025	1,132,055	0.9%	884,368	0.9%	407,986	1.2%	324,862	1.2%	75,354	1.6%
2030	1,184,310	0.9%	925,163	0.9%	432,722	1.2%	343,826	1.1%	81,121	1.5%
2035	1,234,745	0.8%	964,449	0.8%	456,542	1.1%	362,089	1.0%	86,673	1.3%
2040	1,282,411	0.8%	1,001,481	0.8%	479,055	1.0%	379,303	0.9%	91,967	1.2%

Peak Demand Forecast

Summer and Winter Peaks

NorthWestern’s Default Supply peak demand forecast was developed using a linear regression model with weather (cooling degree day (CDD) and heating degree day (HDD)), temperature, monthly energy, and total customers serving as the explanatory variables. Projected DSM and NEM values were then subtracted from the regression results to calculate the peak demand forecasts. NEM is not a factor on the winter peak but it does have a strong impact on the summer peak. The summer peak growth rate is projected to fall from greater than 1% values in previous forecasts to 0.2% in the 2018 forecast, see Table 3-3 below for Default Supply actual and forecasted summer and winter peak demand.

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Table 3-3. Actual and Forecasted Summer and Winter Peak Demand Default Supply

Summer Peak Demand Forecast (MW)				
Historic and Forecast Values Include Losses				
	2018	Less	Less	2018
Year	Actual/ Regression	DSM²	NEM^{1,2}	Forecast
2012	1133			1133
2013	1162			1162
2014	1115			1115
2015	1146			1146
2016	1147			1147
2017	1210			1210
2018	1197	7	5	1186
2019	1212	14	12	1186
2020	1226	21	20	1185
2021	1241	28	32	1182
2022	1255	34	44	1178
2023	1272	40	55	1178
2024	1287	45	66	1176
2025	1303	51	76	1175
2026	1318	57	86	1175
2027	1334	63	96	1175
2028	1349	69	104	1176
2029	1365	75	111	1178
2030	1380	81	117	1182
2031	1396	87	122	1186
2032	1411	93	127	1191
2033	1426	99	131	1195
2034	1440	105	134	1201
2035	1455	111	137	1206
2036	1469	117	140	1212
2037	1483	117	143	1223
2038	1498	117	146	1234
20 Year CAGR	1.1%			0.2%
Avg Increase (MW)	15			2

1. Navigant medium case solar pv - net meter forecast
2. Incremental DSM and NEM

Winter Peak Demand Forecast (MW)				
Historic and Forecast Values Include Losses				
	2018	Less	Less	2018
Year	Actual/ Regression	DSM²	NEM¹	Forecast
2012	1074			1074
2013	1272			1272
2014	1176			1176
2015	1050			1050
2016	1163			1163
2017	1119			1119
2018	1225	15		1210
2019	1236	22		1214
2020	1248	30		1218
2021	1260	37		1223
2022	1271	44		1227
2023	1285	50		1235
2024	1298	56		1241
2025	1310	63		1247
2026	1323	69		1253
2027	1335	76		1259
2028	1348	82		1266
2029	1360	89		1272
2030	1373	95		1278
2031	1385	101		1284
2032	1397	108		1289
2033	1409	114		1295
2034	1421	121		1301
2035	1433	127		1306
2036	1445	134		1311
2037	1456	134		1323
2038	1468	134		1334
20 Year CAGR	0.9%			0.5%
20 Yr Avg Increase	12			6

1. No NEM impact on Winter peak assumed
2. Incremental DSM

Variable Generation Resources Study

Variable Energy Resources Integration Study

Background

To understand how increasing volumes of VERs, such as wind and solar, will impact the operational needs of NorthWestern’s system, NorthWestern retained Navigant to analyze the minute-by-minute variation in NorthWestern’s load over the course of a test year (July 2016 to June 2017).¹ The results of this study provide estimates of the additional regulation and load-following resources needed to integrate increasing amounts of wind and solar generation into NorthWestern’s system while still meeting the requirements of NERC’s Reliability Based Control Standard.²

In this context, “regulation” refers to the use of generation that is on-line, equipped with Automatic Generation Control (AGC), and capable of ramping up or down its full capacity within one minute. This type of resource can change its output quickly to track the minute-by-minute fluctuations in load and output from VERs. “Load following” refers to the use of on-line generation to track intra- and inter-hour changes in load and VERs. Load-following resources are assumed to be able to reach their full capacity in 15 minutes and are split into INC and DEC resources.

¹ Navigant’s complete VER report can be found in Volume 2, Chapter 3.

² The purpose of this standard is to keep the frequency of the interconnection within acceptable limits.

Flexible Capacity Need

Based on the conditions experienced during the test year, Navigant concluded that NorthWestern's system should have a baseline of 120 MW of INC, 155 MW of DEC, and regulation capacity of +/-25 MW (i.e., 50 MW of total regulation comprised of +25MW and -25 MW). Navigant based this recommendation on the expected number of violations of NERC standards that would occur in the test year given the recommend resource levels, as well as the expected Control Performance Standard 1 (CPS1) score and levels of inadvertent generation. Refer to Chapter 4 Existing Resources for information regarding NorthWestern's ability to provide flexible capacity.

Flexible Capacity Need with Additional Renewables

After establishing the baseline levels mentioned above, Navigant examined the incremental INC and DEC needs under three scenarios of higher levels of VERs on the system. These scenarios were designed to reflect the renewable resources that are expected to be built in NorthWestern's balancing area in the near term and the potential for significant additional quantities of wind and solar that could be added to the system.³ The scenarios are:

Scenario A: +185 MW of planned wind

Scenario B: +185 MW of planned wind and +320 MW of additional wind

Scenario C: +185 MW of planned wind and +100 MW of additional solar

To evaluate these scenarios, Navigant simulated hundreds of possible operational profiles for these renewable resources and then layered these profiles onto a wide range of load-following events that NorthWestern experienced during the test year.⁴ A key feature of

³ Information on the precise locations of the simulated VERs can be found on page 12 of the Navigant report in Volume 2, Chapter 3.

⁴ These simulations were based on data from the National Renewable Energy Lab.

these simulations is that they reflect the real historical operating conditions that these resources would have experienced during the test year, including the impacts of regional weather and the locational diversity of the resources.

The locational diversity of the additional VERs considered in the study is particularly important because it plays a large role in determining the degree to which the energy production of these resources is correlated (a higher correlation of output from VERs is more likely to increase the need for load-following resources). In this study, the wind sites were selected to be consistent with NorthWestern's current wind generation portfolio and the locations where proposed wind plants are expected to be built. If the actual development of VERs occurs in locations that are less geographically diverse than the sites included in this study, the results are likely to be an underestimate of the actual INC and DEC needed for integration. This is because VERs that are located closer together would be more likely to experience the same swings in generation and therefore more likely to cause or contribute to load following events.

For each of the scenarios, Navigant determined the levels of INC and DEC that would be needed to limit the expected number of simulations in which a NERC violation occurs to one percent.⁵ The resulting levels of INC and DEC needed for integration under each scenario are presented in Table 3-4.

⁵ Navigant recommended the one percent threshold as the appropriate level because it reasonably balances costs and risks and because it would be very expensive to have sufficient resources to fully eliminate the chance of a NERC violation because there are diminishing returns from further increasing the amount of INC or DEC resources available on the system.

Table 3-4. Navigant VER INC & DEC Recommendation

Navigant Recommendation Under VER Study		
VER Integration Scenario	Additional INC Capacity	Additional DEC Capacity
Scenario A: 185 MW Planned Wind	60 MW	55 MW
Scenario B: 185 MW Planned Wind & 320 MW New Wind	80 MW	120 MW
Scenario C: 185 MW Planned Wind & 100 MW New Solar	60 MW	50 MW

With an increase of 185 MW of wind as in Scenario A, Navigant recommends an additional 60 MW of INC and 55 MW of DEC (these amounts are incremental to the recommended baseline levels, discussed above). With the significantly higher level of wind under Scenario B, relative to Scenario A, Navigant recommends increases of 80 MW of INC and 120 MW of DEC, relative to the baseline levels. The incremental needs under Scenario B are less, relative to the size of the increase in VERs, than under Scenario A because there is a benefit from the geographic diversity in the additional 320 MW of wind, which proportionally lessens the associated load-following impacts.

Despite the additional solar generation in Scenario C, Navigant does not recommend any more load-following resources than under Scenario A. This is because the additional 100 MW of solar does not increase the load-following capacity necessary to achieve the established risk threshold during the worst-case events in the test year, even though it does increase the need for INC and DEC during certain events. However, Navigant notes that with increasing amounts of solar on the system, it expects that solar variability will begin to drive some of the most challenging load-following events. Additionally, because these results are based off of only one year of load data, it will be particularly important for NorthWestern to monitor the regulation and load-following needs under higher levels of solar generation.

Future Capacity Needs

The North American Electric Reliability Corporation (NERC) Reliability Standards as updated through July 3, 2018, defines adequacy as the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Refer to Chapter 2 under NERC Resource Adequacy for NorthWestern’s NERC reserve margin rate of 16.4%.

According to an article published in the Energy Activist of July 27, 2018, by the NW Energy Coalition, the summer of 2018 saw temperatures topping 90 degrees which caused power prices in the Northwest to exceed \$500/MWh. “What these high prices tell us is that it’s time to get into overdrive to address our common capacity and flexibility needs...in the western grid as a whole.”

Energy Load – Balance

NorthWestern’s load-serving obligation requires that Energy Supply acquire resources sufficient to achieve a balance between loads and resources. Load-resource balance is achieved when resources equal loads. The amount and timing of resource acquisitions is determined by comparing the existing resources portfolio to forecast need. Additionally, differences in need between heavy-load and light-load periods must also be considered. Simply averaging or ignoring these differences would not balance either load-serving period and would likely lead to energy deficits during heavy load (HL) hours and energy surpluses during light load (LL) hours.

Figures 3-2 and 3-3 illustrate NorthWestern’s HL and LL load-resource balance over the next 10 years using forecast loads and existing resources. Each figure is compiled using

monthly load values and reflects the seasonality of loads, resulting in a “spiky” appearance. The red line represents loads, while NorthWestern’s existing resources are shown as a resource stack. Comparing forecast loads to the existing resource stack in each figure indicates the energy needed to meet forecast loads.

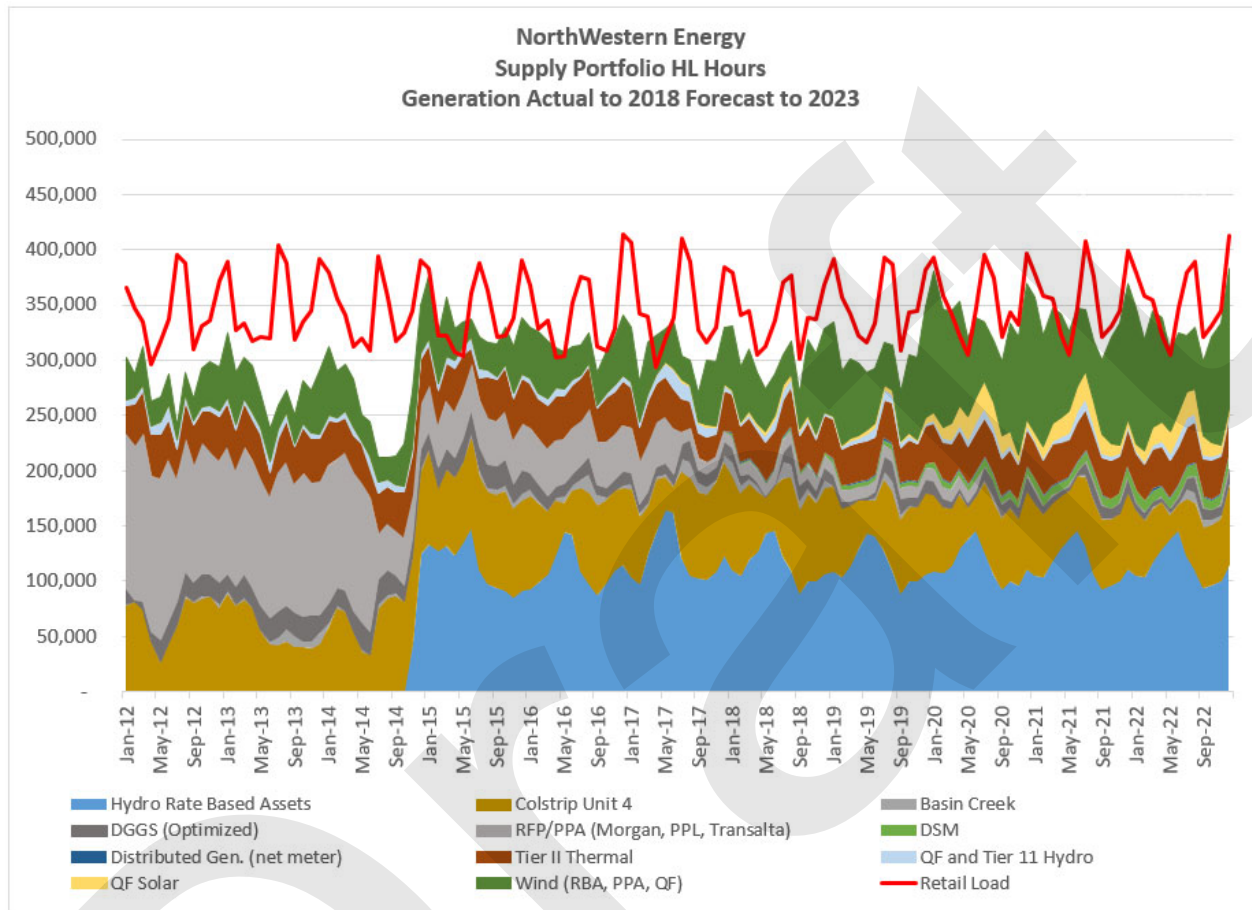
The resource stack in each figure is constructed using monthly energy production for each existing resource. Existing wind resources are shown in the resource stack at their average annual energy production, which is equal to about 38% (also known as annual capacity factor). However, in any one hour, cumulative wind may vary between 0% and 91% of total installed capacity.⁶

Several conclusions can be drawn from Figures 3-2 and 3-3. First, NorthWestern has some ongoing need for resources that produce or can be called on to produce energy during HL hours. Second, NorthWestern has no need for resources that produce energy during LL hours. Must-take resources that are not dispatchable, like wind fall in to the category of providing energy when it is generally not needed, or valued. Additionally, the potential swing in wind production from hour to hour requires flexible, or ramping, resources.

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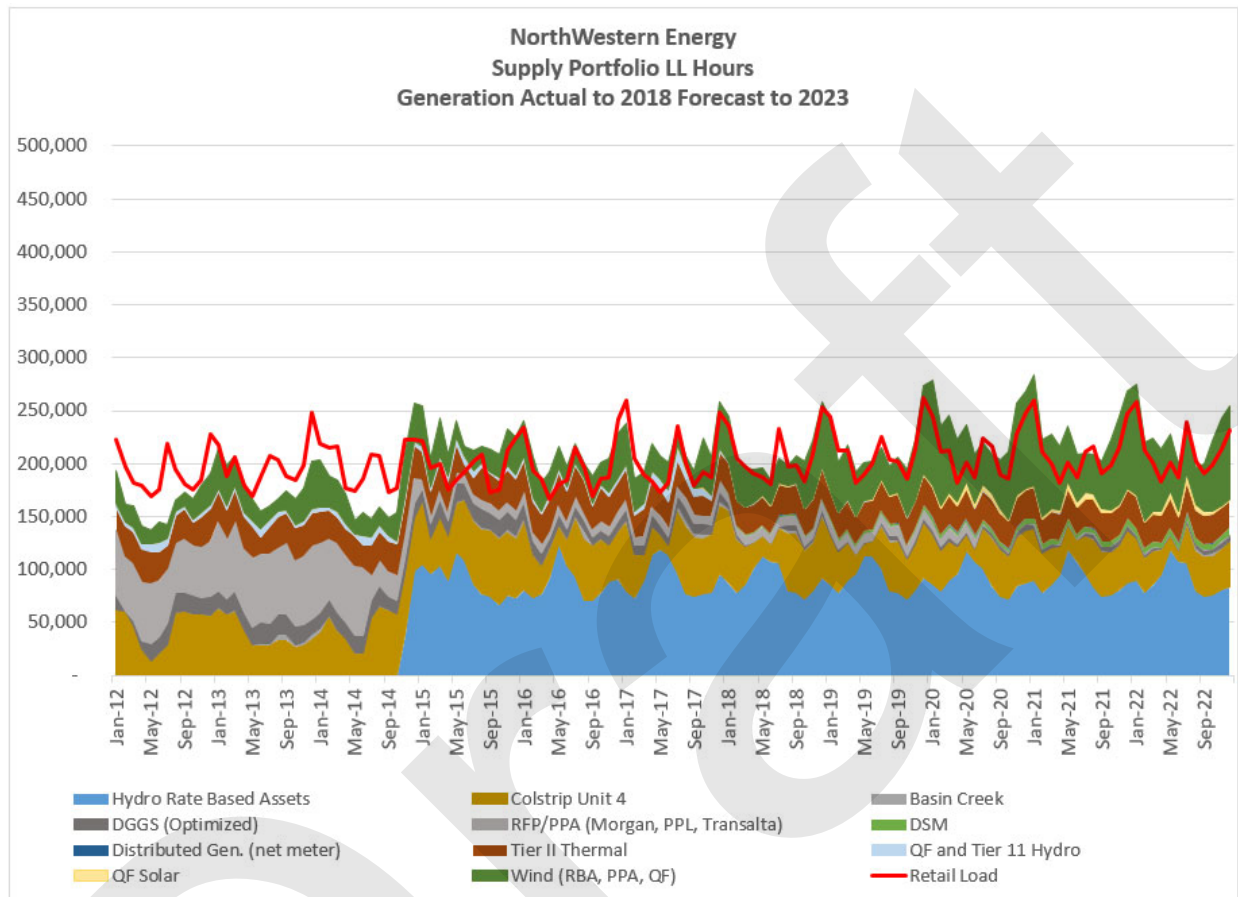
⁶ NorthWestern has observed hourly historical coincident wind production equal to 91% of cumulative installed capacity.

Figure 3-2. Current plus Market 5-Year HL MWh



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Figure 3-3. Current plus Market 5-Year LL MWh



Conclusion

NorthWestern’s resource needs assessment, combined with its current portfolio of resources, drives the selection of resources and portfolio modeling. Other factors driving resource selection are the need to provide system reliability and the integration of variable energy resources, like wind and solar.

CHAPTER 4

EXISTING RESOURCE PORTFOLIO

Large Generation Resources

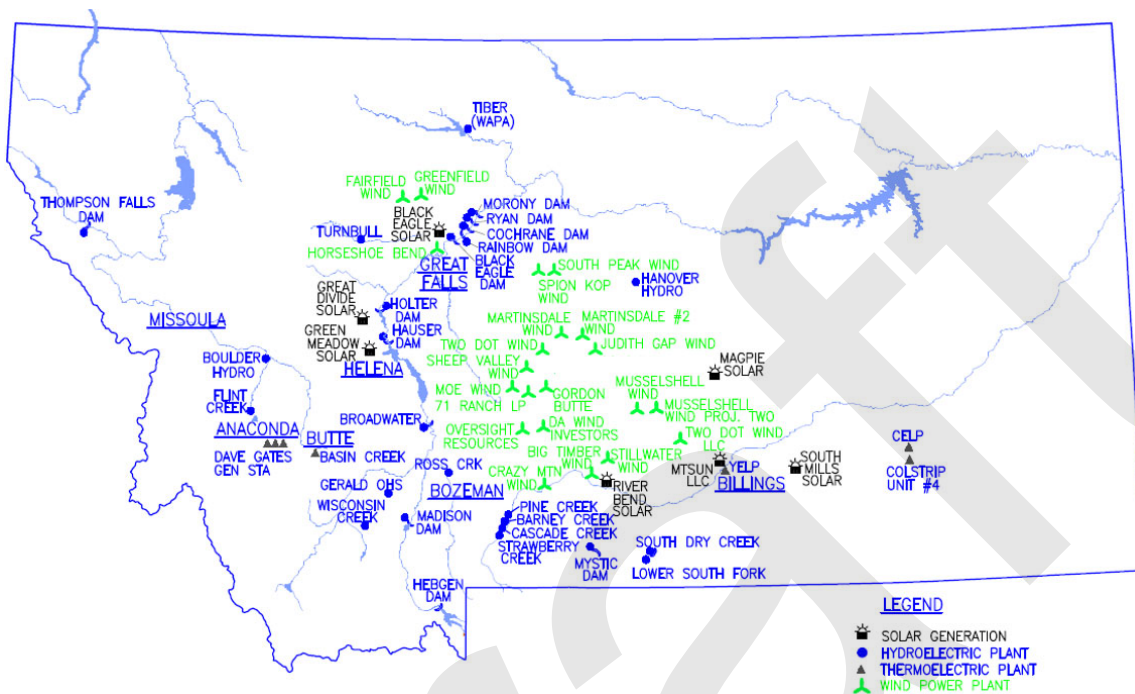
Background

NorthWestern serves our retail customers with a diverse mix of hydro, wind, solar and thermal generation resources. NorthWestern owns some of these resources and we have power purchase agreements (PPAs) with other resource owners. Energy provided by small distributed generation and other demand-side resources is taken into account in our load forecasts. Therefore, these resources are not included as supply-side resources but are discussed separately in a section near the end of this chapter.

Figure 4-1 indicates the approximate locations of all large resources included in NorthWestern's resource portfolio for the 2019 Plan. Some of the resources included in the figure are not yet delivering energy to our system but are included because they have MPSC-ordered rates in place

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Figure 4-1. Montana Electric Generation Facilities



Key Terms and Definitions

Capacity: the maximum electric output that a facility can produce under certain conditions.

Ancillary Services: services that are necessary to support the transmission of capacity and energy from resource to loads while maintaining reliable operation of the transmission system in accordance with good utility practice, including regulation, incremental and decremental capacity, and contingency reserves.

Automatic Generation Control: Equipment that automatically adjusts generation in a balancing authority area from a central location to maintain the balancing authority’s interchange schedule and frequency bias. In other words, generation that is controlled automatically to respond to moment-to-moment fluctuations in the balance of load and generation.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

Regulation: reserves that are responsive to automatic generation control and are sufficient to provide normal regulating margin.

Contingency Reserves: Capacity held for deployment in the event of a contingency, such as a generator or transmission line tripping (becoming unavailable). Contingency Reserves are comprised of Spinning and Non-spinning reserves.

Spinning Reserves: reserve resources that are online and immediately and automatically responsive to frequency deviations and fully deployable within 10 minutes. Also described as unloaded generation that is synchronized with the grid and ready to serve additional demand.

Non-spinning Reserves: reserves that are not online but are capable of coming online to serve demand within 10 minutes or interruptible loads that can be removed from the system within a similar timeframe. Also known as supplemental reserves.

INC: Capacity to increase generation output on short notice (sub-hourly, typically within the 10 to 15 minute timeframe). Also known as incremental capacity).

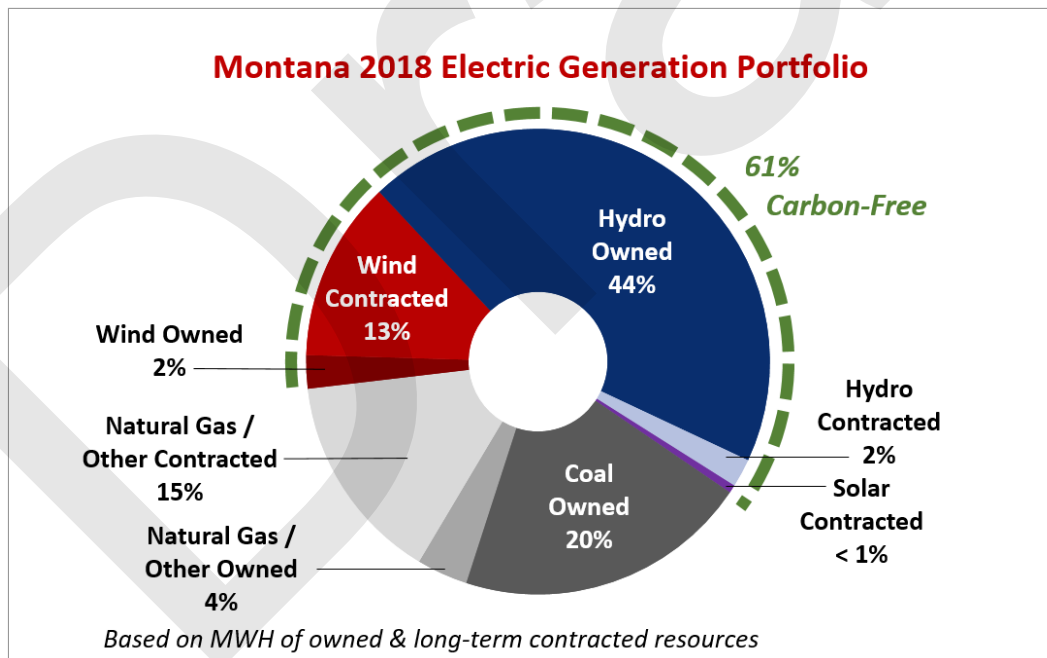
DEC: Capacity to decrease generation output on short notice (sub-hourly, typically within the 10 to 15 minute timeframe). Also known as decremental capacity).

Flexible Capacity Resource: a resource that can be dispatched to provide ancillary services such as regulation, spinning reserve, non-spinning reserve, INC, or DEC. This could include storage and demand response as well as generation.

Energy Production

NorthWestern’s portfolio of resources generated about 88 percent of the energy required to serve its customers during 2017. In 2018, our owned resources and the long-term PPAs in the energy supply portfolio generated just over 6 million MWh energy. As shown in Figure 4-2, 61 percent of these MWh were generated by clean energy resources including hydro, wind and solar.

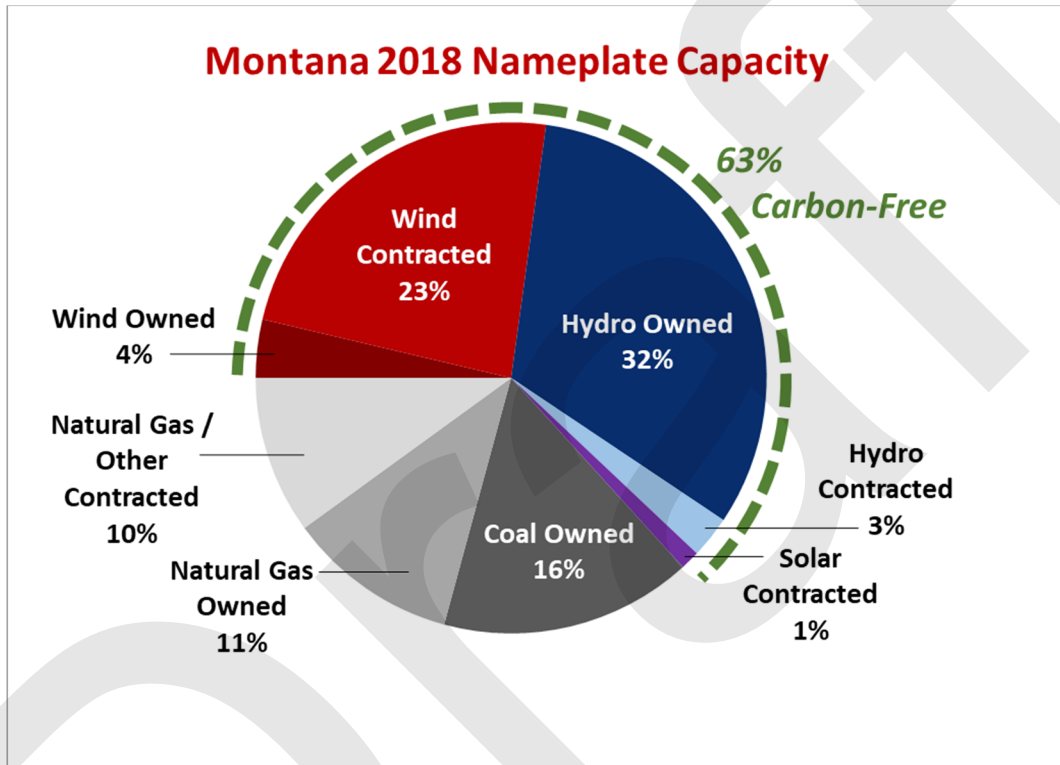
Figure 4-2 2018 Energy Produced by Fuel Source



While Figure 4-2 illustrates the percentages of energy produced from each fuel source, these percentages are not representative of the nameplate capacity of each type of resource.

Figure 4-3 illustrates the nameplate capacity percentages by generation type for the resources in our 2018 portfolio.

Figure 4-3 Nameplate Capacity by Generation Type



As Figures 4-2 and 4-3 indicate, nameplate capacity isn't necessarily indicative of the total energy a particular type of resource generates to serve customers. For example, owned and contracted hydro made up 35% of the nameplate capacity of the portfolio but provided 46% of the energy delivered to customers. On the other hand, owned and contracted wind and solar made up 28% of the nameplate capacity but provided only 15% of the energy delivered to customers.

Existing Large Resources

Summary

NorthWestern's current portfolio of resources is shown in Table 4-1.¹ The large resources in the portfolio have a total nameplate capacity of 1,631 MWs and include hydro, wind, natural gas, coal, and solar generation resources.² A summary of each type of generation resource is provided below.

- Hydro: 484.9 MWs comprised of 448 MWs from rate-based assets, 20.5 MWs from PPAs, and 16.4 MWs from QF agreements.
- Wind: 538.1 MWs comprised of 51.3 MWs of rate-based assets, 135 MWs from PPAs, and 351.5 MWs from QF agreements.
- Natural Gas: 202 MWs comprised of 150 MWs from a rate-based asset and 52 MWs from a capacity purchase agreement.
- Solar: 97 MWs comprised of 17 MWs from QF agreements and 80 MWs from a large QF project with MPSC-ordered rates. Smaller net metering facilities are accounted for by deducting their production from NorthWestern's load forecast.
- Coal: 309 MWs comprised of 222 MWs from a rate-based asset, 35 MWs from a waste coal-fired QF facility, and 52 MWs from a petroleum coke-fired QF facility.³

¹ Note that South Peak Wind, Crazy Mountain Wind and MTSun are not yet commercially operable; all have estimated commercial operation dates of December 2019.

² The capacity of each facility is generally equal to the nameplate capacity but may vary based upon limitations to dispatch, generator or turbine limitations, or equipment upgrades.

³ The QFs in this category have a total capacity of 106.5 MWs, however their contracted capacity is only 87 MWs, which includes 35 MWs from the CELP waste coal facility and 52 MWs from the YELP petroleum coke facility.

Table 4-1. NorthWestern’s Resource Portfolio

Portfolio Resources	Facility Capacity (MW)	Expiration (Date)	Peak Load Contribution (MW)	Reg UP (MW)	Reg Down (MW)	Spin (MW)	Non-spin (MW)	INC (MW)	DEC (MW)
Hydro Generation									
Thompson Falls*	94.00	Rate Based	43.00	Varies	Varies	0 - 17	0	0	0
Cochrane*	62.00	Rate Based	25.00	Varies	Varies	1 - 6	0	0 - 18	6 - 29
Ryan*	68.00	Rate Based	40.00	Varies	Varies	0	0	2 - 10	26 - 36
Rainbow*	64.00	Rate Based	33.70	0	0	5 - 10	0	0	0
Holter*	53.00	Rate Based	32.00	0	0	0	0	0	0
Morony*	49.00	Rate Based	24.00	0	0	0	0	0	0
Black Eagle*	21.00	Rate Based	12.00	0	0	0	0	0	0
Hauser*	17.00	Rate Based	14.00	0	0	0	0	0	0
Turnbull Hydro LLC	13.00	12/31/2032	0.00	0	0	0	0	0	0
Mystic*	12.00	Rate Based	5.00	Varies	Varies	0 - 7	0	0	0
State of MT DNRC (Broadwater Dam)	10.00	6/30/2024	2.80	0	0	0	0	0	0
Madison*	8.00	Rate Based	6.00	0	0	0	0	0	0
Small Hydro Aggregate (See Below)	13.92	Various	1.70	0	0	0	0	0	0
Tiber Montana LLC	7.50	6/1/2024							
Flint Creek Hydroelectric LLC	2.00	1/16/2037							
Hydrodynamics Inc (South Dry Creek)	1.20	6/30/2021							
Wisconsin Creek LTD LC	0.55	7/1/2019							
Boulder Hydro Limited Partnership	0.51	6/30/2022							
Lower South Fork LLC	0.46	1/16/2037							
Ross Creek Hydro LC	0.45	6/30/2032							
Gerald Ohs (Pony Generating Station)	0.40	12/10/2020							
Allen R. Carter (Pine Creek)	0.30	6/30/2024							
Donald Fred Jenni (Hanover Hydro)	0.24	6/30/2034							
Hydrodynamics Inc (Strawberry Creek)	0.19	6/30/2023							
James Walker Sievers (Cascade Creek)	0.07	10/1/2019							
James Walker Sievers (Barney Creek)	0.06	11/14/2019							
Natural Gas Generation									
Basin Creek	52.00	12/31/2034	49.40	0	0	0	52	52	52
DGGS 1	50.00	Rate Based	47.50	43	43	43	50	50	50
DGGS 2	50.00	Rate Based	47.50	43	43	43	50	50	50
DGGS 3	50.00	Rate Based	47.50	43	43	43	50	50	50
Thermal/Coal Generation									
Colstrip Unit 4	222.00	Rate Based	206.46	0	0	24	24	100	100
Yellowstone Energy Limited Partnership (BGI)	52.00	12/31/2028	48.36	0	0	0	0	0	0
Colstrip Energy Limited Partnership	35.00	6/30/2024	32.55	0	0	0	0	0	0
Wind Generation									
Judith Gap Energy LLC	135.00	12/31/2026	8.20	0	0	0	0	0	135
Stillwater Wind LLC (WKN)	80.00	1/11/2043	TBD	0	0	0	0	0	80
South Peak Wind LLC	80.00	Est 12/1/2034	TBD	0	0	0	0	0	80
Crazy Mountain Wind LLC	79.50	Est 1/1/2045	TBD	0	0	0	0	0	79.5
Spion Kop Wind	40.00	Rate Based	8.30	0	0	0	0	0	40
Greenfield Wind LLC	25.00	11/1/2041	2.20	0	0	0	0	0	25
Big Timber Wind LLC (Greycliff)	25.00	4/1/2043	TBD	0	0	0	0	0	25
Fairfield Wind LLC (Greenbacker)	10.00	12/31/2033	0.10	0	0	0	0	0	0
Musselshell Wind Project LLC	10.00	3/24/2036	0.20	0	0	0	0	0	10
Musselshell Wind Project Two LLC	10.00	3/24/2036	0.30	0	0	0	0	0	10
Two Dot Wind Farm LLC	11.28	Rate Based	0.10	0	0	0	0	0	11.28
Gordon Butte Wind LLC	9.60	3/21/2036	0.40	0	0	0	0	0	9.6
Cycle Horseshoe Bend Wind LLC	9.00	8/31/2035	0.00	0	0	0	0	0	0
71 Ranch LP	2.70	1/1/2024	TBD	0	0	0	0	0	2.7
DA Wind Investors LLC	2.70	1/1/2024	TBD	0	0	0	0	0	2.7
Oversight Resources LLC	2.70	1/1/2024	TBD	0	0	0	0	0	2.7
Small Wind Aggregate (See Below)	5.26	Various	0.00	0	0	0	0	0	0
Two Dot Wind LLC (Martinsdale Colony South)	2.00	4/23/2028							
Two Dot Wind LLC (Broadview East Wind)	1.60	1/11/2043							
Two Dot Wind LLC (Martinsdale Colony)	0.75	4/23/2028							
Two Dot Wind LLC (Sheep Valley Ranch)	0.46	4/23/2028							
Two Dot Wind LLC (Moe Wind)	0.45	4/23/2028							
Solar Generation									
MTSun LLC (MPSC Final Order 7535a)	80.00	Est 1/1/2030	TBD	0	0	0	0	0	0
Green Meadow Solar LLC	3.00	4/1/2042	TBD	0	0	0	0	0	3
South Mills Solar 1 LLC	3.00	4/1/2042	TBD	0	0	0	0	0	3
Black Eagle Solar LLC	3.00	10/1/2042	TBD	0	0	0	0	0	3
Great Divide Solar LLC	3.00	10/1/2042	TBD	0	0	0	0	0	3
Magpie Solar LLC	3.00	10/1/2042	TBD	0	0	0	0	0	3
River Bend Solar LLC	2.00	4/1/2042	TBD	0	0	0	0	0	2

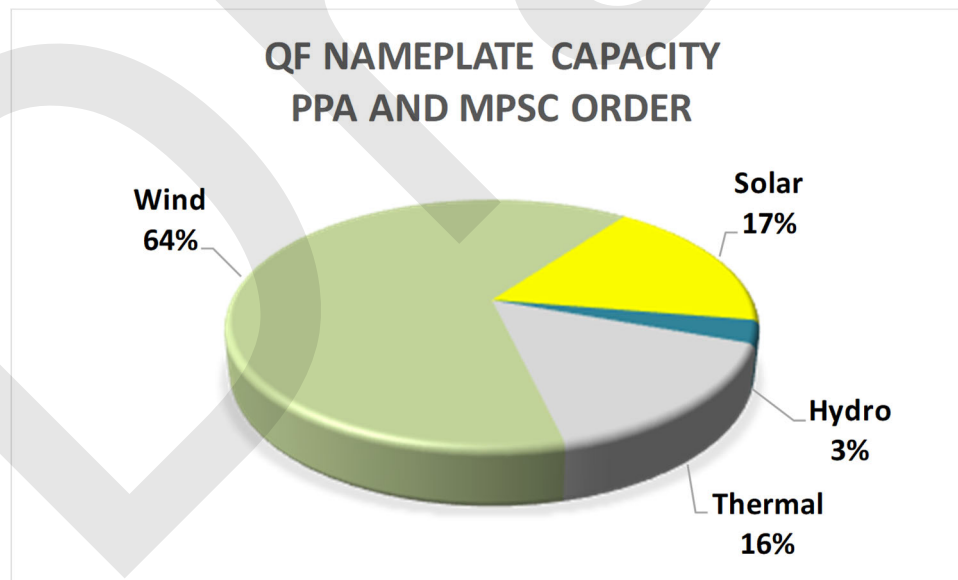
TBD = To be determined
Note: * Updated from 2015 Plan.

Significant Additions of Qualifying Facilities

Recently, NorthWestern has had requests from an additional 2,545 MWs of QF projects for avoided cost calculations or draft PPAs. Of these requests, 104.8 MWs fall under the 3 MW standard offer limit for the QF-1 Tariff. The larger projects, up to 80 MWs in size, include 1,417 MWs of solar, 888 MWs of wind, and 134.7 MWs of other technologies or combination projects. NorthWestern’s average retail load is only 747 MWs.

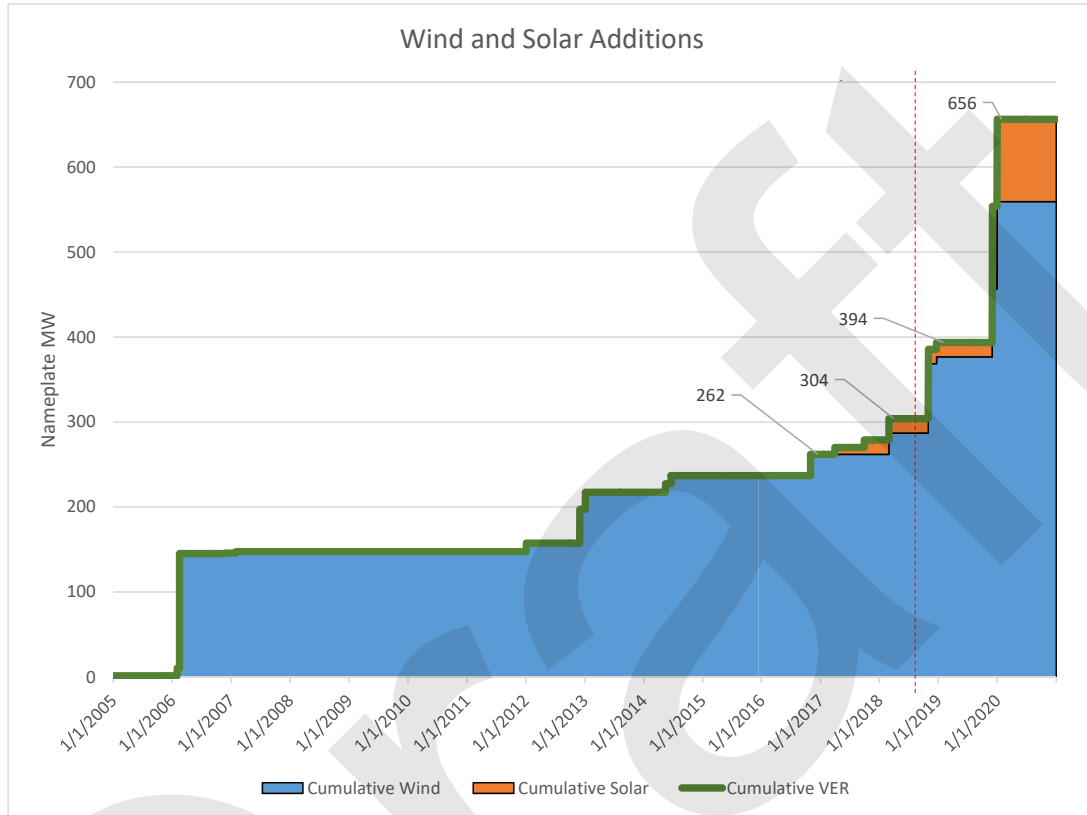
In 2017, the nameplate capacity of the QFs in NorthWestern’s portfolio totaled just over 550 MWs and, over half of the contracts for those QFs were added after the beginning of 2016.

Figure 4-4. QF Capacity by Fuel Type



The historical and anticipated additions of QF variable energy resources to NorthWestern’s portfolio system are in Figure 4-5.

Figure 4-5. Nameplate MW Additions of Variable Resources – Historical and Future



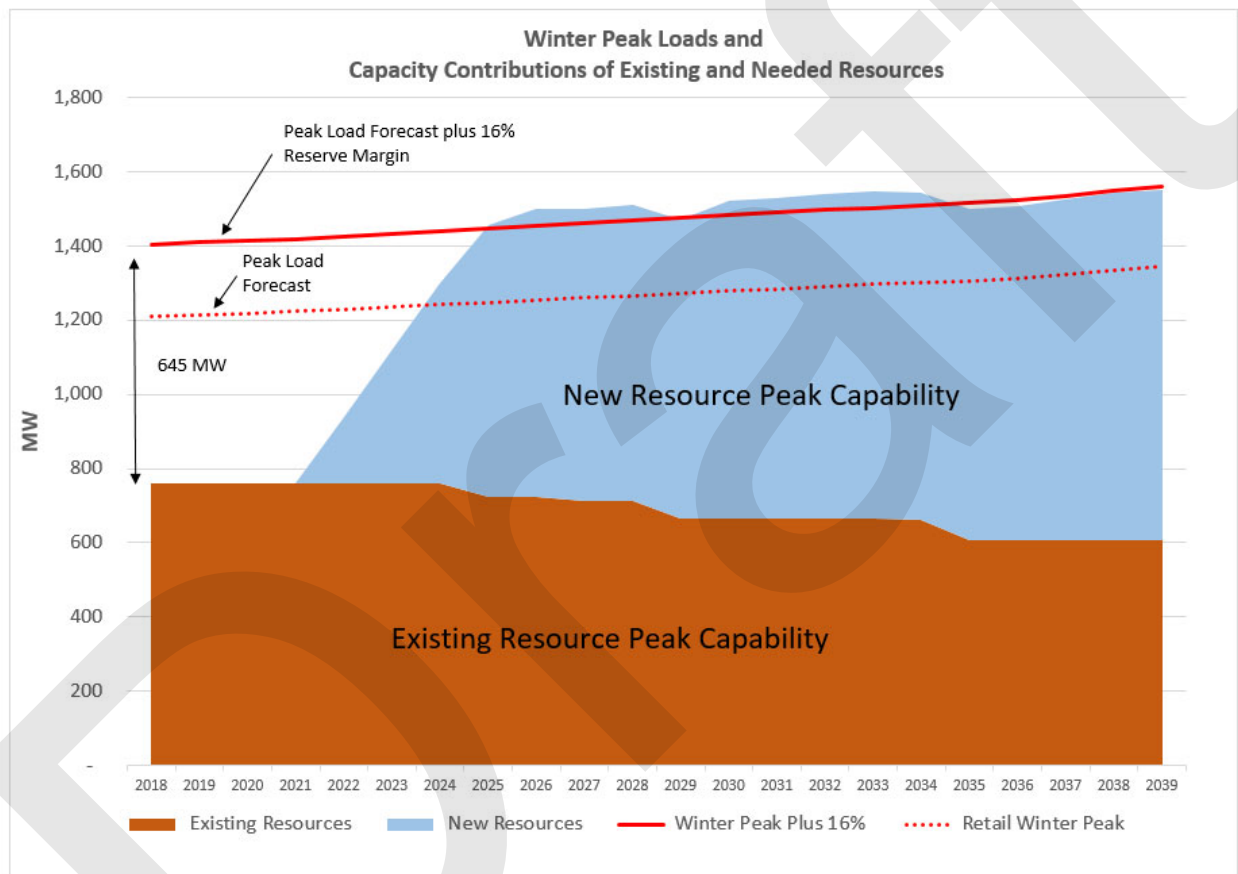
Peaking Load Contribution (Capacity at time of system peak)

The “peak load contribution” column of Table 4-1 indicates the level of capacity each resource is expected to contribute during peak load periods. For thermal resources, peak load contribution is calculated as the nameplate capacity less lost capacity due to forced outages. For hydro, solar, and wind resources, the peak load contribution is determined by examining each resource’s historic level of production during historic peak load periods on our system.

Figure 4-6 compares the combined peaking capacity of the existing resources in NorthWestern’s portfolio with our peak load forecasts. The figure shows the peaking capacity of our portfolio is currently about 645 MWs short of the peak load forecast

including reserve margin. The peaking capacity deficit is forecast to increase to 955 MWs over the forecast period without the addition of resources capable of providing peaking capacity.

Figure 4-6. Capacity Contribution and Resource Adequacy



Approximately 738 MWs of capacity is expected to be available from our current portfolio of resources during peak load events which is about 63% of our customers’ needs during peak load hours. However, the capacity contribution percentage will vary based on actual circumstances during a peak load event as shown in Figure 4-7 which depicts the capacity contributions and loads during the 2017 peak load day.

Figure 4-7. Capacity Contribution on Peak Load Day

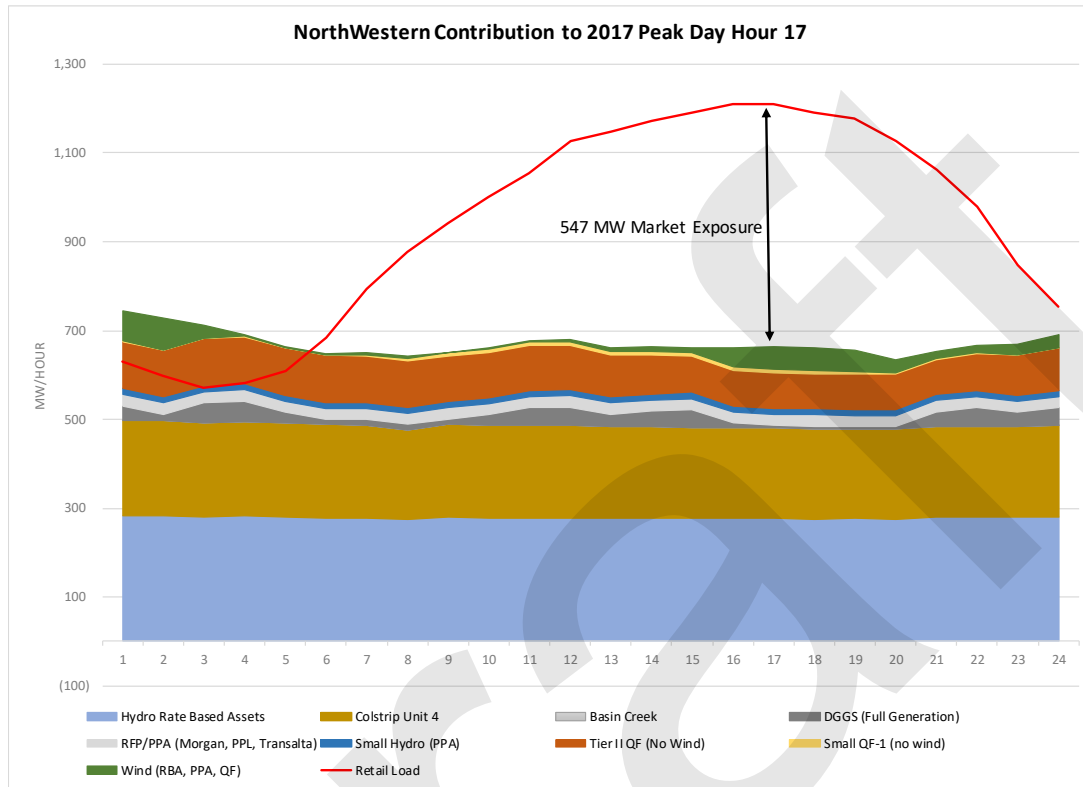


Table 4-2 provides the percentages each resource category was contributing to the 2017 peak load day.

Table 4-2. Capacity Contribution on 2017 Peak Day

MW Contribution to Peak 2017	
Hydro Rate Based Assets	22.9%
Colstrip Unit 4	16.9%
Basin Creek	0.0%
DGGS (Full Generation)	0.5%
RFP/PPA (Morgan, PPL, Transalta)	2.1%
Small Hydro (PPA)	1.1%
Tier II QF (No Wind)	6.6%
Small QF-1 (no wind)	0.7%
Wind (RBA, PPA, QF)	4.1%
Market	45.2%
Total Peak Requirement 1,210	100%

Dispatchable Capacity

Dispatchable capacity is important in that it allows NorthWestern to integrate variable resources including renewable generation and follow load within its system while maintaining the reliability BAL-001-2 NERC requirements for the Balancing Authority. Refer to chapter 5 for additional explanation of capacity requirements.

NorthWestern’s current portfolio has limited capacity that can ramp up within the hour (see Table 4-3). The primary INC capacity comes from Colstrip Unit 4, DGGS, Basin Creek, and some from Cochrane and Ryan dams. Multiple resources in the portfolio can provide DEC, including some QF resources, but the curtailments required for the QF resource to provide DEC typically require compensation that would reflect no monetary loss for the project owners and it is therefore rarely economic to call on them for this capability. It is important to note that some resources may be able to provide multiple ancillary services but they cannot be used for these two requirements at the same time (because if they are called upon to provide one service they are no longer available to provide the other).

Table 4-3. Percent of Intra-Hour Plant use for RBC

2017	Basin Creek	Colstrip Unit 4	Cochran Ryan	DGGS	Mystic	Thompson Falls	Contracted	Total
INC	37%	22%	17%	25%				100%
DEC	16%	47%	31%	6%				100%
Spin		19%	51%		10%	18%	2%	100%
NonSpin	4%			96%				100%

The intra-hour capacity available from the hydro resources, presented in Table 4-4, varies with the seasons and generation facility flows.

Table 4-4. Hydro Intra-Hour Capacity

Intra-Hour Facility		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Thompson Falls	Capacity	94	94	94	94	94	94	94	94	94	94	94	94
	Spin MW	10	8	9	1	0	3	14	10	4	7	14	17
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Cochrane	Capacity	62	62	62	62	62	62	62	62	62	62	62	62
	Spin MW	3	3	1	6	6	3	4	5	5	5	5	4
	INC MW	13	17	12	6	0	3	11	5	12	13	12	18
	DEC MW	-10	-11	-19	-23	-29	-22	-12	-7	-6	-6	-8	-10
Ryan	Capacity	68	68	68	68	68	68	68	68	68	68	68	68
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	7	10	8	2	3	2	5	8	7	5	5	5
	DEC MW	-34	-32	-36	-43	-35	-28	-30	-26	-30	-29	-35	-34
Rainbow	Capacity	64	64	64	64	64	64	64	64	64	64	64	64
	Spin MW	10	10	10	7	7	5	10	10	10	10	10	10
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Mystic	Capacity	12	12	12	12	12	12	12	12	12	12	12	12
	Spin MW	3	2	2	1	1	0	0	0	4	6	7	4
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Holter	Capacity	53	53	53	53	53	53	53	53	53	53	53	53
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Marony	Capacity	49	49	49	49	49	49	49	49	49	49	49	49
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Black Eagle	Capacity	21	21	21	21	21	21	21	21	21	21	21	21
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Hauser	Capacity	17	17	17	17	17	17	17	17	17	17	17	17
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Madison	Capacity	8	8	8	8	8	8	8	8	8	8	8	8
	Spin MW	0	0	0	0	0	0	0	0	0	0	0	0
	INC MW	0	0	0	0	0	0	0	0	0	0	0	0
	DEC MW	0	0	0	0	0	0	0	0	0	0	0	0
Hydro System Total		448	448	448	448	448	448	448	448	448	448	448	448
	Spin MW	26	23	22	15	14	11	28	25	23	28	36	35
	INC MW	20	27	20	8	3	6	13	10	20	20	17	23
	DEC MW	-44	-43	-55	-66	-64	-50	-42	-33	-36	-35	-43	-44

Monthly hourly averages or calculated based on history available and INC.

Note: Hydro updated from 2015 Plan.

Demand Side Resources

Demand Side Resources – Acquisition and Programs

DSM Goals

Since the 2015 Plan, NorthWestern has received from Nexant Consulting Inc. (Nexant) an updated Electricity Energy Efficiency Market Potential Study (“Electric Energy Potential Study”) which provided information as to the amount of remaining achievable, cost-effective electric energy savings through Demand Side Management (“DSM”) based upon the available in NorthWestern’s Montana service territory. The Electric Energy Potential Study evaluated the cost effectiveness of DSM energy savings based on the total resource cost (“TRC”) test. The TRC test is a ratio of benefits (the avoided cost value of energy saved) to the total program costs (utility program implementation costs and estimated customer costs). Nexant applied TRC ratio of 1.0 or greater to screen measures for cost effectiveness. This study estimated the remaining potential of annual incremental energy savings for the time period of 2015-2034 to be 61.7 aMWs or 7% of the baseline sales. Based on that value for DSM measures, and including estimates for energy savings through the Northwest Energy Efficiency Alliance (NEEA) market transformation activities, as well as energy savings acquired through activities funded with Universal System Benefits (USB) dollars, NorthWestern has established its annual energy savings acquisition goal at the level of 4.35 aMWs each year for 5 years (2016-2017 through 2020-2021) and a goal of 3.77 aMWs each year for the next 15 years (2021-2022 through 2035-2036). The DSM measures savings reflect incentive levels at 50% of incremental measure costs and a moderate market adoption rate from the study. While estimated savings from USB-funded programs are included as noted in this Plan, the expenses are not included as they are covered with USB revenues.

Electric avoided costs are a primary determinant of DSM cost-effectiveness. Therefore, eligible DSM measures, achievable cost-effective DSM potential, proper DSM Program rebate/incentive levels, and expenditure levels for various other DSM Program activities such as marketing and outreach must be evaluated against the most recent avoided costs. This treatment of DSM cost-effectiveness is consistent with the Qualifying Facilities Docket No. D2016.5.39 and the Commission’s Supplemental Comments in the Electricity Supply Resource Procurement Plan Docket No. N2015.11.9. avoided costs are consistent with the Qualifying Facilities Docket No, D2016.5.39 methodology with capacity and energy values that calculate to a 20 year levelized rate of \$0.041 per kilowatt-hour.

NorthWestern recognizes that the annual goal of 4.35 aMWs for energy savings is fairly aggressive given still lower avoided cost rates, and anticipated changes in manufacturing standards for lighting in 2020 which will result in smaller quantities of cost effective energy savings from this universal technology. This may also be indicative of the success of prior DSM efforts to secure the easiest options for retail customers.

Table 4-5. DSM Historical Acquisition

Historical DSM Savings & Spending (DSM only no NEEA or USB)			
Tracker Year	Spend or Budget	DSM Savings aMW	\$/aMW Acquired
2013-2014	\$ 7,526,764	5.14	\$ 1,463,928
2014-2015	\$ 4,399,366	4.19	\$ 1,050,340
2015-2016	\$ 4,831,958	3.51	\$ 1,375,707
2016-2017	\$ 5,347,761	4.25	\$ 1,257,564
2017-2018	\$ 6,290,975	5.26	\$ 1,195,387
Cumulative	\$ 28,396,824	22.36	\$ 1,270,257

Cost effective DSM will continue to be acquired in the same manner as in the past – through operation of the E+ Rebate and E+ Business Partners programs, and the regional Simple Steps lighting program. NorthWestern has renewed its contract with DNV GL to encourage additional energy savings by persuading customers, through NorthWestern’s E+ Commercial Lighting Programs, to purchase LEDs or other lighting technologies instead of less efficient bulbs. DNV GL also supports energy savings through the E+ Commercial Electric Rebate Program for New or Existing facilities.

NorthWestern has continued its focus on acquiring energy efficiency in the commercial sector and has contracts in place with several firms for services in support of the E+ Business Partners Program, the E+ Commercial Lighting Rebate Program, and the E+ Commercial Electric Program for New or Existing facilities. The firms are:

- National Center for Appropriate Technology
- McKinstry Essention
- CTA Associates, Inc.
- Energy Resource Management, Inc.
- CLEAResult Consulting, Inc.
- Associated Construction Engineering, Inc.

These contractors are compensated by NorthWestern on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual DSM project that is completed with the contractor’s involvement.

These contractors are supported by DNV GL employees who have responsibility for direct contact, marketing of E+ programs to commercial/small industrial customers in an effort to identify, qualify, and cultivate energy saving projects for follow-up by the contractors.

DSM Budget and Spending

The tables below show the Electric DSM Acquisition Goals that include energy savings estimates from DSM, NEEA, and USB for each year and forecast program expenses for DSM and NEEA over the 20-year period. The DSM savings component is developed from the Electric Potential Study; the NEEA component represents NorthWestern’s expectation of the electric savings produced through NEEA activities for NorthWestern’s Montana’s service territory; and the USB component represents NorthWestern’s current expectations of the electric savings that will be generated by USB programs.

Table 4-6. DSM Forecast Acquisition

Forecast Electric DSM Acquisition				
Tracker Year	DSM Acquisition (aMW)	NEEA DSM Acquisition (aMW)	USB Acquisition (aMW)	Total DSM, NEEA, and USB
2016-2017				
2017-2018				
2018-2019	3.49	0.41	0.45	4.35
2019-2020	3.49	0.41	0.45	4.35
2020-2021	3.49	0.41	0.45	4.35
2021-2022	2.95	0.40	0.42	3.77
2022-2023	2.95	0.40	0.42	3.77
2023-2024	2.95	0.40	0.42	3.77
2024-2025	2.95	0.40	0.42	3.77
2025-2026	2.95	0.40	0.42	3.77
2026-2027	2.95	0.40	0.42	3.77
2027-2028	2.95	0.40	0.42	3.77
2028-2029	2.95	0.40	0.42	3.77
2029-2030	2.95	0.40	0.42	3.77
2030-2031	2.95	0.40	0.42	3.77
2031-2032	2.95	0.40	0.42	3.77
2032-2033	2.95	0.40	0.42	3.77
2033-2034	2.95	0.40	0.42	3.77
2034-2035	2.95	0.40	0.42	3.77
2035-2036	2.95	0.40	0.42	3.77

Table 4-7. DSM Forecast Acquisition Expense

Forecast Electric DSM Expense			
Tracker Year	DSM Forecast Incremental Program Expense	NEEA Forecast Program Expense	Total Forecast Incremental Program Expense DSM + NEEA
2016-2017			
2017-2018			
2018-2019	\$ 5,163,861	\$ 1,500,000	\$ 6,663,861
2019-2020	\$ 5,422,054	\$ 1,500,000	\$ 6,922,054
2020-2021	\$ 5,693,156	\$ 1,500,000	\$ 7,193,156
2021-2022	\$ 5,041,324	\$ 1,500,000	\$ 6,541,324
2022-2023	\$ 5,293,390	\$ 1,500,000	\$ 6,793,390
2023-2024	\$ 5,558,059	\$ 1,500,000	\$ 7,058,059
2024-2025	\$ 5,835,962	\$ 1,500,000	\$ 7,335,962
2025-2026	\$ 6,127,760	\$ 1,500,000	\$ 7,627,760
2026-2027	\$ 6,434,148	\$ 1,500,000	\$ 7,934,148
2027-2028	\$ 6,755,856	\$ 1,500,000	\$ 8,255,856
2028-2029	\$ 7,093,649	\$ 1,500,000	\$ 8,593,649
2029-2030	\$ 7,448,331	\$ 1,500,000	\$ 8,948,331
2030-2031	\$ 7,820,748	\$ 1,500,000	\$ 9,320,748
2031-2032	\$ 8,211,785	\$ 1,500,000	\$ 9,711,785
2032-2033	\$ 8,622,374	\$ 1,500,000	\$ 10,122,374
2033-2034	\$ 9,053,493	\$ 1,500,000	\$ 10,553,493
2034-2035	\$ 9,506,168	\$ 1,500,000	\$ 11,006,168
2035-2036	\$ 9,981,476	\$ 1,500,000	\$ 11,481,476
Cumulative	\$ 125,063,594	\$ 27,000,000	\$ 152,063,594

NorthWestern notes that a future DSM budget is a long-term estimate that may be used for long range resource planning. Each one-year budget forecast is based on current year results and knowledge gained from past program operation and is likely to deviate from

the values established in the long range budget forecast presented above, and as evidenced by the five years of data in the Actual Spend column of Table 4-5 above.

DSM Programs and NEEA

NorthWestern continues to offer a variety of programs, services and resources to help our Montana customers to better manage energy costs. The following are electric DSM Programs funded through energy supply rates:

- **Simple Steps Program** –This program buys down LED prices for residential customers at retailers through a regional campaign facilitated by the Bonneville Power Administration.
- **E+ Commercial Lighting Rebate Program** – Offers prescriptive and custom rebates for the replacement of less efficient lighting products with high efficiency technologies.
- **E+ Commercial Electric Rebate Program for New or Existing Facilities** – Rebates are available to electric customers for qualifying electric measures.
- **E+ Business Partners Program** – Provides customized incentives to commercial and industrial customers for electric and natural gas conservation. Examples of projects include measures to improve lighting, heating, ventilating and cooling (HVAC) systems, refrigeration, air handling, and pumping systems. New and existing facilities are eligible.
- **Northwest Energy Efficiency Alliance (NEEA)** – NEEA is a regional non-profit organization supported by utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. Through regional leveraging, NEEA accelerates “market transformation” or the development and adoption of energy efficient products and services in Montana,

Washington, Idaho, and Oregon. NEEA’s regional market transformation activities target the residential, commercial, industrial and agricultural sectors.

USB Programs

Additional electric energy savings are produced from Universal System Benefits (USB) funded programs that will continue into the foreseeable future. The electric energy savings produced from these USB programs are counted toward annual DSM goals. The costs to operate these programs are not included in the energy supply resource planning process. The following energy saving programs are supported through USB funds:

- **E+ Free Weatherization Program** – Provides insulation and other efficiency improvements at no cost to Low Income Energy Assistance Program (LIEAP) qualified space-heating customers of NorthWestern.
- **E+ Energy Audit for the Home** – Free onsite energy audit and mail-in survey audit.
- **E+ Energy Appraisal for Businesses** – Free onsite energy audit that focuses on identifying electric conservation opportunities for small commercial customers on NorthWestern’s electric distribution system. The customer receives a report with recommendations customized to the facility.
- **E+ Irrigator Program** – Provides financial incentives for the installation of energy efficient electric conservation in irrigation systems.
- **Building Operator Certification** – Building Operator Certification is an international professional development program for managers and operating engineers of commercial and public facilities and is available to commercial customers in partnership with the Northwest Energy Efficiency Council.

- **E+ Renewable Energy Program** – Provides financial incentives to non-profit and government/public electric customers for qualifying small-scale solar photovoltaic, wind, and hydroelectric systems in Montana.

Future Updates

NorthWestern is updating the Electric Potential Study in an effort to define the demand or capacity savings potential in NorthWestern's Montana electric service territory and inform DSM-based avoided capacity cost values. NorthWestern has contracted with Nexant, Inc. to complete this work, which is expected to be finalized in the first half of 2019. NorthWestern will be evaluating the savings estimates for its Montana service territory and contract associated with NEEA's 2020-2024 Business Plan. The results of these activities may result in adjustments to the forecasts noted in this plan.

Additional information on the programs listed is available at NorthWestern's website at www.NorthWesternEnergy.com/Eplus.

Small Distributed Generation Resources

Net Energy Metering Study

NorthWestern currently has about 2,400 customers that have their own small-scale solar PV systems that provide power to NorthWestern's electrical grid. The customers that own these systems are net metering customers and they are able to offset their electric use and receive a credit for the excess energy produced, above use. This credit is currently equal to NorthWestern's full \$/kWh retail rate.

In April 2017, the Montana Legislature passed House Bill 219, which was signed by the Governor of Montana on May 3, 2017. The legislation required NorthWestern to conduct an economic analysis and evaluation of solar PV NEM benefits and costs in the State of Montana. NorthWestern was required to conduct a NEM study of the costs and benefits of customer-generators and submit the study to the Montana Public Service Commission (MPSC) before April 1, 2018. Navigant was retained by NorthWestern to conduct the study. The results of Navigant’s NEM study complies with the law, and could support the development of a new rate class for NEM solar if the results of the study justify the need to create a separate NEM rate class.⁴

Navigant estimated the value streams for NEM resources across a range of benefit and cost categories and under three different 25-year scenarios reflecting different potential rates of solar adoption in Montana.⁵ These scenarios were derived from a study prepared in 2017 for the MPSC by the NREL, with adjustments to ensure that the forecasts were realistic in the context of the NEM Study. The three scenarios Navigant considered were:

- **Low Adoption:** equivalent to NREL’s “unfavorable” scenario
- **Medium Adoption:** the average of the Low and High Scenarios
- **High Adoption:** adoption not to exceed substation-level limits based on reverse power thresholds, the exceedance of which would require upgrades to

⁴ The full report can be found in Volume 2, Chapter 3.

⁵ The benefits and costs derived in the study are based on the categories outlined in the Minimum Information Requirements in Attachment 1 of the MPSC Notice of Commission Action dated August 9, 2017. The categories considered in the study are: avoided energy costs, avoided capacity costs, avoided transmission and distribution capacity costs, avoided system losses, avoided RPS compliance costs, avoided environmental compliance costs, market price suppression effects (fuel hedging), avoided risk (e.g., reduced price volatility), avoided costs for grid support services, avoided outages costs, non-energy benefits, reduced revenue, administrative costs, interconnection costs, and integration costs.

NorthWestern’s distribution system to avoid reverse power flows or thermal voltage violations when midday load is low but solar output is high

Because the High Adoption scenario is limited to adoption levels that are low enough to avoid upgrade costs on the distribution system, other upgrade costs that would be necessary at higher levels of adoption—such as those for interconnection and integration—can also be avoided. Thus, these costs are estimated at zero throughout the study period. The adoption levels over the 25-year study period for each scenario are presented in Table 3-4.

Table 4-8. Navigant NEM Adoption Scenarios

Adoption Scenario (MW)			
Year	Low	Medium	High
2018	16	19	22
2019	22	31	40
2020	29	47	65
2021	37	67	97
2022	45	88	131
2023	55	108	161
2024	67	128	189
2025	80	146	212
2026	95	163	231
2027	112	180	248
2028	129	196	262
2029	142	208	273
2030	155	218	281
2031	167	227	288
2032	177	236	294
2033	186	243	299
2034	193	249	305
2035	199	254	310
2036	203	259	316
2037	206	265	323
2038	209	270	330
2039	212	275	338
2040	214	280	346
2041	215	284	353
2042	217	288	358

To determine how much power is likely to be generated from customer-owned solar generation, and the hourly production over the year, Navigant followed the production

shape methodology used in NREL’s study. This method uses a weighted mixture of rooftop orientations and locations that exist on NorthWestern’s system in 2018.

Using these generation profiles, Navigant estimated the value streams associated with each category of cost and benefit for each solar adoption scenario (Low, Medium, and High). The study also estimated how these values would change if the government imposed a tax on carbon emissions starting in 2028. The estimated values for each category of benefits and costs are presented in the following table.⁶

Table 4-9. Navigant NEM Value Streams

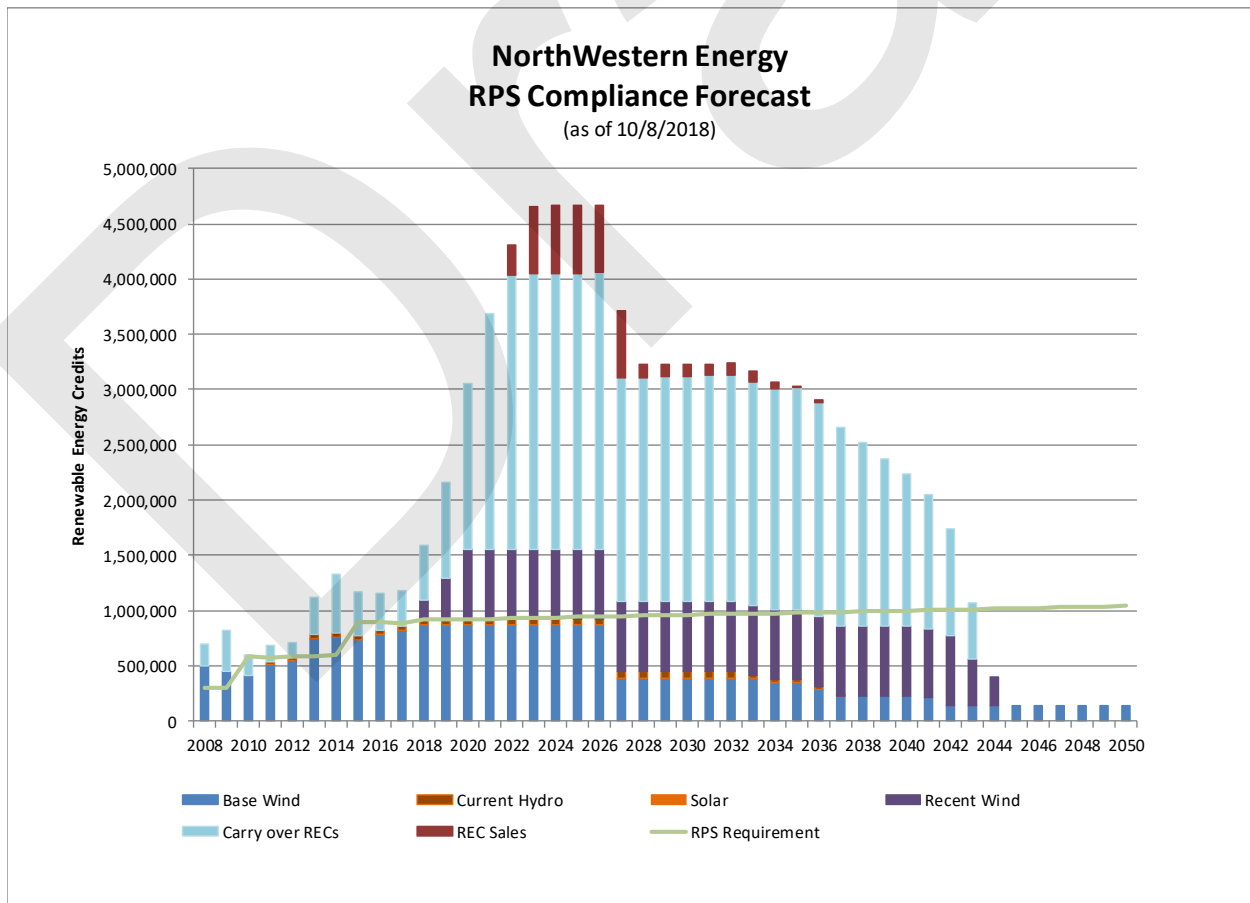
Carbon Price	Yes	Yes	Yes	No	No	No
Adoption Scenario	Low	Med	High	Low	Med	High
Avoided Energy Costs	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03
Avoided Capacity Costs	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01
Avoided T&D Capacity Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Avoided System Losses	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Avoided RPS Compliance Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Avoided Environmental Compliance Costs	\$0.01	\$0.01	\$0.01	\$0.00	\$0.00	\$0.00
Market Price Suppression Effects (Fuel Hedging)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Avoided Risk (e.g., reduced price volatility)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Avoided Grid Support Services Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Avoided Outages Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Non-Energy Benefits	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Reduced Revenue	(\$0.15)	(\$0.14)	(\$0.14)	(\$0.15)	(\$0.14)	(\$0.14)
Administrative Costs	(\$0.00)	(\$0.00)	(\$0.00)	(\$0.00)	(\$0.00)	(\$0.00)
Interconnection Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Integration Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Net Value	(\$0.10)	(\$0.10)	(\$0.10)	(\$0.11)	(\$0.11)	(\$0.11)

⁶ More detailed information on the calculation of these costs and benefits can be found in the NEM study Volume 2, Chapter 3.

Renewable Portfolio Standards

NorthWestern maintains its commitment to do everything it can to meet the requirements imposed upon it under the Montana Renewable Power Production and Rural Economic Development Act, §69-3-2001, MCA, et. Seq., labeled as the Renewable Resource Standard but commonly referred to as the Renewable Portfolio Standard (RPS). NorthWestern’s current requirement is to meet an energy requirement of 15% of its yearly retail sales (MWh) from eligible renewable resources and for an additional capacity (MW) requirement under its share of purchases from a state total of 75 MWs of community renewable energy projects (CREP). NorthWestern’s share of the CREP requirement has been established at 65.4 MWs.

Figure 4-8. Montana RPS Compliance



Renewable Energy Credits (REC)

Under the MCA, a "Renewable energy credit" means a tradable certificate of proof of 1 megawatt hour of electricity generated by an eligible renewable resource that is tracked and verified by the commission and includes all of the environmental attributes associated with that 1 megawatt-hour unit of electricity production. Montana requires NorthWestern to validate all REC it acquires and uses to meet its obligation through the WECC established Western Renewable Energy Generation Information System (WREGIS).

Based on its current contractual commitments and forecasted energy generation from the RPS qualified facilities, NorthWestern anticipates it will meet the required 15 % of sales through 2043. During 2017 the RPS facilities generated 862,980 RECs with NorthWestern's 15% of sales equaling 542,553 REC that were required to be retired to meet its 2017 obligation. WREGIS reports that the volumes allowed to be carried forward into future years are 320,427 REC. Under the MCA, REC that are not retired to meet a utility obligation can be carried forward for up to two years. Based on forecasted RPS generation NorthWestern anticipates that around the year 2022, it will have more REC than it requires to meet its obligations and will have to sell excess REC before they are no longer able to be used for compliance.

Community Renewable Energy Projects

NorthWestern currently has 36.335 MWs of its CREP capacity requirement obligation under the MCA. In its attempt to meet the total required capacity, NorthWestern has issued multiple RFPs and negotiated PPAs for additional CREP projects that have either been deemed to not qualify or otherwise meet the MCA rules. In 2018, NorthWestern acquired Two Dot Wind, making it eligible to qualify as a CREP resource. At a work session held on November 28th, 2018, the MPSC certified Two Dot wind as an 11 MW CREP resource.

NorthWestern will continue to pursue all available avenues to obtain its remaining CREP obligation as soon as possible.

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CHAPTER 5

REGIONAL MARKET TRANSFORMATION

NorthWestern's Path to the Western Energy Imbalance Market ("EIM") and Beyond

Regional Market Development

Background

There are two full regional markets in the WECC: The CAISO and the Alberta Electric System Operator (AESO). CAISO manages the transmission system owned by the three large investor-owned utilities in California and operates full day-ahead and realtime markets. AESO manages and operates the provincial electric grid. ISOs and RTOs are independent entities that operate transmission facilities owned by others, coordinate planning of the transmission system, and operate markets. ISOs typically include both day-ahead markets and realtime markets for energy and ancillary services. Some also include capacity markets. ISOs dispatch generation resources owned by others to economically meet customer loads within the market footprint. Both CAISO and AESO have been operating for over twenty years.

Stakeholders in other areas of the WECC have been discussing, analyzing, and attempting to develop organized markets since the 1990s. In the last five to ten years, those efforts have moved away from full ISO development to the development of EIMs. EIMs share some characteristics of RTOs and ISOs, but there are key differences. The major similarity is that all of these entities operate markets which accept offers and dispatch resources on a sub-hourly basis to meet load requirements. Unlike RTOs and ISOs, EIMs do not provide

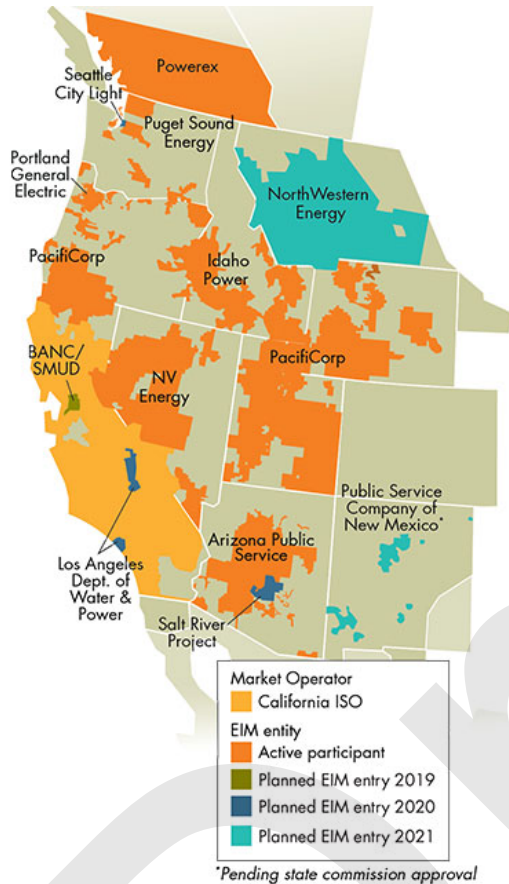
ancillary services, manage congestion, or administer an Open Access Same-time Information System (OASIS) site, and they do not take on reliability responsibility.

The efforts to develop EIMs have occurred for both reliability and economic reasons. Both the reliability and economic aspects are driven in large part by the need to integrate increasing amounts of intermittent generation into the portfolios of virtually all utilities in the region. EIMs improve reliability by providing increased region-wide situational awareness to Balancing Authorities (BAs) and making better use of available generating capacity in the region. They also improve economics by efficiently dispatching generators to meet loads across a regional footprint rather than within BAs.

While the individual BAs retain their reliability responsibility, EIMs have resource sufficiency requirements that obligate participating BAs to carry enough capacity to meet their own internal needs. These requirements are designed to keep a participating BA from entering an hour in a capacity- or energy-short position and relying on the EIM to meet its load-serving obligations. Participation in an EIM helps make efficient use of resources, but it does not reduce a BA's need for capacity. Depending on the specifics of the resource sufficiency requirement, participation could drive the need for additional capacity.

Western EIM

In 2011, efforts to develop an EIM in the West began ramping up. A number of groups, including WECC, the Western Interstate Energy Board, and WSPP explored the ideas and issues surrounding the potential creation of the market. These efforts resulted in an initiative sponsored by the Northwest Power Pool (NWPP) that would have created an EIM for the Pacific Northwest. NorthWestern was an active participant in the NWPP effort, which ultimately failed in 2015.



Meanwhile, in 2013, PacifiCorp and the CAISO announced their plans to form what would become the Western EIM. The Western EIM went live in October of 2014, and since that time, NV Energy, Arizona Public Service, Puget Sound Energy, Portland General Electric, Idaho Power, and Powerex have joined the market. Five additional utilities – Balancing Authority of Northern California / Sacramento Municipal Utility District, Seattle City Light, Salt River Project, Los Angeles Department of Water and Power, and Public Service Company of New Mexico have signed implementation agreements to join in the next few years. The map to the left shows the current and planned market participants.

The Western EIM has provided significant value to the customers of participating utilities. CAISO estimates that the total gross economic benefits for participating entities have totaled over \$500 million from the inception of the market through September of 2018. The economic benefits come primarily from efficient economic dispatch of resources across the market footprint to meet customer load on a realtime basis. In addition, the market benefits customers by enhancing reliability through enhanced operational visibility and by improving the integration of renewables by taking advantage of weather and load diversity across the wide geographic area covered by the market.

NorthWestern Analysis of the Western EIM

In 2016, NorthWestern began an in-depth analysis of the Western EIM to determine whether joining the market would make sense for the company and our customers. We engaged two consultants to help with the analysis. Utilicast performed a market assessment and gap analysis, and Energy and Environmental Economics (E3) performed a benefits study.

Utilicast Study

Utilicast performed a high-level assessment of the potential market options available to NorthWestern and the system, process, organizational, and personnel changes that would be necessary to operate in organized markets.

Utilicast worked with NorthWestern to identify several existing and potential wholesale markets in the West. These included the Western EIM, the AESO, the Mountain West Transmission Group (MWTG), the Southwest Power Pool (SPP), regionalization of the CAISO, and a Northwest market. While several of these potential alternatives had appealing aspects, they had significant challenges as well. The Northwest market, MWTG, and the regionalized CAISO were conceptual and would require several years of development; and participation in AESO and SPP would likely require transmission construction. This left the Western EIM as the only viable market alternative that was worth detailed analysis.

The remainder of the Utilicast assessment focused on understanding the current state of NorthWestern's technology, processes, infrastructure, and personnel and what would be necessary to participate in the Western EIM. Utilicast performed an in-depth analysis of NorthWestern's operations, including transmission, energy supply, load forecasting, metering, and other areas. This analysis also included cost estimates for the

implementation of the software, hardware, processes, staffing, and other changes that would need to take place. This work served as an initial roadmap for the path NorthWestern would follow if we made the decision to pursue the EIM.

E3 Study

E3 performed a detailed analysis of the potential economic benefits of NorthWestern participation in the EIM. The modeling approach was to use production cost modeling to estimate the benefits resulting from participation in the EIM by comparing NorthWestern's generation costs, market revenues, and market costs as an EIM participant with those of a business as usual (BAU) case in which NorthWestern does not participate in EIM.

As a starting point, E3 used the PLEXOS database that was developed by the Pacific Northwest National Laboratory for the WECC study in 2012. E3 updated the database during its 2015 EIM study for Portland General Electric and subsequent EIM study for Idaho Power Company and made revisions specific to the NorthWestern BA and neighboring systems in this study.

The study calculated benefits in two categories, sub hourly dispatch benefits and savings from reductions in flexibility reserves. The dispatch benefits were calculated by running a realtime BAU case that held energy transfers (purchases and sales) between non-participating BAs equal to the hour-ahead scheduled amounts, and comparing that to an EIM case that allowed NorthWestern to transact energy within the hour with other EIM entities. The savings from reduced flexibility reserves were calculated based on the CAISO methodology for calculating the savings from diversity across the market footprint.

E3 analyzed a base case and two alternative scenarios. The base scenario reflected EIM membership of the entities who were participating at the time of the study and those who

had announced plans to join and reflected renewables penetration levels consistent with then-existing RPS targets in the states within the EIM footprint. The first alternative case examined an expanded EIM footprint that includes all northwest BAs in addition to those in the base scenario. The second alternative scenario modeled high renewables buildouts in California and Oregon that were under consideration at the time.

The study results indicated that annual benefits for NorthWestern would range from \$1.3 million to \$3.0 million, with a base case of \$1.8 million.

Other Considerations and NorthWestern's Decision to Join EIM

Based on the results of the Utilicast and E3 studies, NorthWestern determined that there would be customer benefit in joining the EIM. However, at the time the work was completed in early 2017, other market development activity had advanced to the point that it warranted further consideration.

Specifically, the MWTG had announced that it intended to become a part of SPP. SPP began a stakeholder process to work toward the integration of the MWTG footprint into the market, with a target go-live date of October of 2019. NorthWestern's South Dakota operations are already in the SPP market, so the potential to integrate Montana operations into that market had some appeal. However, NorthWestern does not have direct transmission interconnection with the MWTG members, so there were significant challenges to address as well. We began discussions with MWTG members and other neighboring utilities about the potential to expand the SPP market beyond the MWTG footprint. We also participated in the integration discussions in the SPP stakeholder process from the perspective of our existing South Dakota membership.

The MWTG plans to join SPP were abruptly derailed in April of 2018 when one of the key members of the group, Xcel Energy’s Public Service Company of Colorado (PSCo), announced that they were leaving the group and discontinuing their consideration of joining SPP. The remaining members of MWTG indicated that they would continue their efforts, but PSCo’s departure significantly changed their situation. MWTG began analysis on whether it would make sense to continue to proceed without PSCo. The results of the analysis were not made public, but in October, Black Hills Energy announced that it would not pursue membership in SPP at this time, and the Western Area Power Authority (WAPA) announced that it was suspending MWTG activity.

Meanwhile, in late 2017, Peak Reliability and PJM Connex announced plans to explore the development of an organized market in the West. This effort continued through the spring of 2018, but ultimately did not gain enough support among utilities and others to survive. The effort ceased in July of 2018.

In the summer of 2018, the Bonneville Power Administration (BPA) announced that it was initiating a public stakeholder process regarding the potential for BPA to join the EIM in 2022. Since July, BPA has hosted several public meetings and webinars and accepted comments from stakeholders. At the time of this writing, it appears likely that BPA will make the decision to join EIM.

Throughout this period, NorthWestern continued to meet with MWTG members, SPP staff, current and planned EIM members, CAISO staff, and utilities that have not yet committed to joining a market. We also made two, day-long site visits to current EIM members to gain a better understanding of the operational impacts of EIM membership.

Through these discussions and through several internal meetings, the EIM emerged as the most appropriate path forward for NorthWestern. We met with MPSC staff in and Montana Consumer Counsel (MCC) in June to update them on the status of NorthWestern's views, and we indicated at that time that the EIM appeared to be the most likely path. We also presented material to ETAC in February and July of 2018, describing the market development activity and indicating that a NorthWestern decision to join EIM was likely.

BPA's move toward the EIM, along with the number and size of the current and planned members, as well as others that appear likely to announce their plans in the coming months, have given the EIM significant size. The total load of the EIM members and those who have signed implementation agreements is about 80% of the load in the Western Interconnection. For a number of reasons, NorthWestern is wary of the prospect of existing outside of the organized market while an increasing number of our neighbors and peers become part of the market. One consideration is whether a robust bilateral market will continue to exist outside of EIM as the market continues to develop. A second is that as an outsider, NorthWestern does not have a voice in the specific rules and market structure as they are updated and change over time. Additionally, if there is a future move toward a full RTO market in the West, the transition will be much easier if NorthWestern is aligned with its peers as a member of EIM than it would be if NorthWestern was one of the few parties operating outside of that market.

The NorthWestern executive team formally approved the decision to join EIM in September. We negotiated an implementation agreement with CAISO and executed it on November 8 with a go-live date of April 2021.

Future Market Development

EIM Enhanced Day-Ahead Market

In early 2018, CAISO kicked off a process to enhance the day-ahead market within the full ISO footprint. The changes are primarily geared toward improving the operation within California in the full ISO, but they changes will also create a platform that would allow for the EIM to be extended to include a day-ahead market. The enhancements to the ISO's day-ahead market are targeted to go live in 2019. The extension to EIM participants would occur in a second phase. This extension has not yet been formally introduced as a stakeholder process, but CAISO has been working with current EIM members and organizations that have executed implementation agreements to propose a potential framework. Once this work is complete, if current members and CAISO support moving forward, a stakeholder process will be initiated regarding the day ahead EIM. This market could go live as early as 2022.

An organized day-ahead market across the EIM footprint could be a significant development. The EIM has provided value for the participants, but a day-ahead market that optimizes resources across a wide footprint over multiple hours could provide even more value, depending on the market construct. As is the case with the existing EIM, EDAM would include a resource sufficiency requirement. This means that, in order to participate, NorthWestern would need to demonstrate on a day-ahead basis the ability to meet its load, ramps, and uncertainty throughout the day.

Potential Future Western RTO

With the increased pace of market development in the West over the last five years, NorthWestern views the development of a full RTO as extremely likely. There are several reasons for this. The continued fast pace of solar and wind generation throughout the region will continue to increase the need for flexible resources and market structures to

accommodate them. The EIM helps in the realtime horizon. The EDAM, if it is implemented across the EIM footprint, could be even more valuable because it would allow for the day-ahead commitment of resources to meet net load ramps in the market. A full RTO or ISO, without transmission pancaking issues and with broad transmission planning, would ultimately provide the most value. For this Plan, we are assuming that full RTO will be implemented in 2025.

EIM Operations

Changes from Current Operations

NorthWestern's Energy Supply and Transmission operations will change significantly when we join EIM. The following section describes, at a high level, some of the expected impacts from the Energy Supply perspective.

The current structure of the non-EIM electricity market consists of bilateral transactions. This means that the terms of energy purchases and sales are negotiated directly between the two counterparties to a transaction or trade. While there may be some effects from EIM on day-ahead and longer transactions, the market itself addresses intra-hour balancing, so its biggest effect will be on hourly operations.

In non-EIM operations, the NorthWestern Energy Supply realtime scheduler makes hour-ahead bilateral purchases or sales to balance forecasted supply with forecasted load. Within the hour, any deviations from that balance either from load or generation is countered with NorthWestern's flexible resources. Because of this need, NorthWestern must set aside or reserve flexible capacity to increase generation (INC) and decrease generation (DEC) to be used to make up any differences that occur within the hour. For example, if wind generation is lower than expected, NorthWestern may have to increase

generation from a flexible resource in its portfolio (for example, DGGS) to keep the system in balance and comply with NERC standards. If wind generation is higher than expected, NorthWestern may have to decrease a flexible resource in order to keep the system in balance and in compliance. Note that in EIM, NorthWestern will remain a BA with responsibility to comply with all applicable reliability standards, but instead of just the resources in NorthWestern's own fleet, resources from throughout the market footprint are potentially available to help meet imbalances.

EIM addresses only within-hour balancing, so NorthWestern will still engage in bilateral trading up to the hour-ahead time horizon. A key difference in EIM will be that, instead of reserving resources to increase or decrease going into an hour, NorthWestern will offer these flexible resources into the market. Within the hour, the EIM will meet load and imbalances across the market area by economically dispatching resources every five minutes. The market uses security constrained dispatch, meaning that transmission and reliability constraints are honored. The EIM uses dynamic schedules to transfer energy among EIM Entities, meaning that the schedules for these transfers are created automatically by the market.

In EIM, the BA or transmission function within NorthWestern will be the EIM Entity. In addition to all of its current responsibility as a BA, the EIM Entity is responsible for monitoring generation and transmission information within its boundaries and communicating this information to the EIM Market Operator on a realtime basis. NorthWestern's Energy Supply group will be responsible for determining which resources will participate in the market (Participating Resources) and which will not (Non-Participating Resources). The Energy Supply group's role is known as the Participating Resource Scheduling Coordinator (PRSC). The PRSC will also determine the prices at which to offer resources into the market.

Resource Sufficiency & Capacity Requirements

A key element of the EIM is that EIM Entities cannot lean on the market for capacity. Each EIM Entity must demonstrate on an hourly basis that it has the resources and ramping capability available to meet its own needs as a BA (less an allowance for the benefit created by the load and generation diversity across the footprint). This requirement takes the form of the Resource Sufficiency (RS) tests. These tests occur three times in each hourly cycle, at T-75 (75 minutes before the start of the clock hour), T-55, and T-40. The tests are intended to ensure that each EIM Entity can meet its own reliability obligations. If an EIM Entity fails any of the RS tests for any hour, intra-hour EIM transfers to or from other EIM Entities will not be allowed during that hour. The RS evaluation consists of four components: 1) Balancing Test; 2) Bid Capacity Test; 3) Flexible Ramping Sufficiency Test; and 4) Feasibility Test.

The Balancing Test ensures that each EIM Entity has scheduled resources that match (within a tolerance) its forecasted load. This test compares the base schedules with the hourly demand forecast. The scheduled resources must be within 1% of the demand forecast to pass the screen.

The Bid Capacity Test compares the total INC and DEC bid range from Participating Resources within the EIM Entity with the demand forecast plus and minus historical intertie deviations. The EIM Entity passes the Bid Capacity Test if there is sufficient capacity to meet the forecast plus historical deviation and the forecast minus the historical deviation.

The Flexible Ramping Sufficiency Test ensures that each EIM Entity has enough ramping resources to meet expected upward and downward ramping needs. This is similar to the Bid Capacity Test except that it also includes the ramp rates of the Participating Resources.

The Feasibility Test uses base schedules submitted to the market to perform a power flow feasibility test. This test determines if the base schedules submitted by participants would violate any transmission constraints.

CHAPTER 6

TRANSMISSION SYSTEM

NorthWestern's Electric Transmission System

Overview

NorthWestern's Montana electric transmission system covers over 97,000 square miles in the western two-thirds of Montana. The system includes about 7,000 miles of transmission and sub transmission facilities with voltages ranging from 50 kilovolt (kV) to 500 kV. The system includes over 280 circuit segments, 79 transmission or transmission/distribution substations, and over 100,000 poles/structures.

Key Concepts and Definitions

A review of key concepts and definitions is useful for understanding NorthWestern's transmission system and some of the issues and challenges facing NorthWestern.

- NorthWestern's transmission system is made up of 230 kV, 161 kV, 115 kV, and 100 kV systems that connect the various load centers in the state as well as sub-transmission 50 kV and 69 kV systems that serve many local areas.
- The jointly owned Colstrip 500 kV transmission system makes its way from Colstrip in eastern Montana to western Montana where it interconnects with the Bonneville Power Administration's (BPA) 500 kV Montana Intertie facilities at Townsend. BPA's 500 kV Montana Intertie extends from Townsend to the Garrison substation. NorthWestern and the other Colstrip owners hold firm transmission rights on the Montana Intertie facilities.

- Open Access - Federal Energy Regulatory Commission (FERC) Order 890: provides for non-discriminatory access to jurisdictional transmission systems to all eligible customers.
 - NorthWestern has an Open Access Transmission Tariff (OATT) on file with FERC.
- Total Transmission Capacity (TTC): total designed and approved transmission capacity of a transmission path.
- Available Transmission Capacity (ATC): available transmission capacity after considering firm commitments.
- Reliability: adequacy and security of the transmission system to operate properly under stressed conditions.

The Colstrip 500 kV Transmission System

It is well known the 500 kV transmission lines were built at the time the Colstrip generation plants were constructed and the transmission lines are the primary asset used to export the other Colstrip owners' shares of the generation out of Montana to load centers in Washington and Oregon. What may not be as well understood is the value of the 500 kV system to Montana customers. The 500 kV system is the backbone of the Montana transmission system, and it provides NorthWestern with a very strong path from east to west across the state with which to reliably serve all of our Montana customers. The 500 kV system effectively ties together the lower transmission voltage systems in the state at three substations – Colstrip, Broadview and Garrison. The Garrison substation is owned by BPA and in addition to NorthWestern's rights on the Montana Intertie, NorthWestern also has other transmission facilities that terminate at Garrison. In addition, the 500 kV system provides the greatest access to and from the regional market. This is extremely important to allow NorthWestern the ability to import power into Montana to serve our

customers – both our retail energy supply customers and the unbundled customers that receive transmission service under our OATT described in more detail below. This import capability is especially important as Montana generation is slated to be shuttered.

Customers Served by the Transmission System

NorthWestern’s transmission system serves four types of customers – retail, network, interconnection, and point to point (PTP).

- The retail customers are NorthWestern’s bundled transmission, distribution and energy supply customers. The Montana Public Service Commission (MPSC) approves rates for NorthWestern’s service to retail customers.
- Network customers are generally electric cooperatives and federal power marketing agencies, such as the BPA, as well as “choice customers.” Choice customers elected, under deregulation, to purchase electric commodity service from a supplier other than MPC (now NorthWestern), or are new customers since then with loads that do not qualify for electric supply service from NorthWestern. Network customers take transmission delivery service under NorthWestern’s FERC OATT to serve load within NorthWestern’s footprint.
 - It is extremely relevant to note NorthWestern’s belief that there is no entity “planning” for the electricity supply for the choice customers in Montana. The choice customer group relies on the market and as generation in Montana is reduced, there will be more competition for available resources and transmission capacity which will increase the risk associated with NorthWestern relying too heavily on the outside market to serve our retail customers.

- To be clear, NorthWestern has the responsibility to reliably deliver energy to all of our customers even though we do not have control of the resources used to serve a large percentage of our customers.
- Interconnection customers are generation customers seeking interconnection to NorthWestern’s transmission system. One example of an interconnection customer is a Qualifying Facility (QF). While NorthWestern processes QF interconnections under the FERC generation interconnection rules with MPSC permission, as a general rule, QFs are under the jurisdiction of the MPSC. Non-QF generation interconnection customers are provided service under NorthWestern’s FERC OATT.
- PTP customers move power into and out of NorthWestern’s system using the transmission system. NorthWestern serves PTP customers through our FERC OATT.

Other Services Provided by the Transmission System

NorthWestern also manages the transmission system as a Balancing Authority (BA), with responsibility for ensuring that system demand and supply are in constant balance. To support the continuous flow of electricity, NorthWestern provides ancillary services which are services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice and include regulation, incremental and decremental capacity, and contingency reserves. When demand and supply are not in balance, equipment damages, cascading outages, or blackouts can result. As a BA, NorthWestern must comply with the North American Electric Reliability Corporation’s (NERC) reliability standards. One of the greatest challenges faced by NorthWestern as a BA is being able to balance loads and

resources as more and more variable energy resources (VERs) are added to the energy supply portfolio while remaining compliant with NERC standards.

In April of 2015, FERC approved NERC Standard BAL-001-2 – Real Power Balancing Control Performance (aka, Reliability Based Control (RBC)). This was a significant change from the former Control Performance Standard 2 (CPS2). In early 2016, NorthWestern began operating under RBC. Under RBC, performance includes a component directly tied to the Western Electricity Coordinating Council’s (WECC) overall operating frequency (measured in hertz). This allows for some flexibility to BA operators if their own system variance is “helpful” to the WECC system variance. This would occur if a BA was in a frequency position opposite that of the overall WECC. However, if an individual BA’s variance is detrimental to the operation of the WECC, RBC requires the BA to take more immediate action than was required under the old CPS2 standard. While CPS2 compliance was measured on a monthly basis, RBC requires compliance within 30 minutes of when the BA’s variance moves out of tolerance limits. In addition to the moment-to-moment response that we receive from resources on automatic generation control, the system balancing efforts now require additional generation facilities capable of responding within minutes. NorthWestern uses the Dave Gates Generating Station (DGGS), Colstrip Unit 4, the Hydros, and Basin Creek to meet RBC requirements.

As more and more variable resources like wind and solar are connected to the transmission system and become part of NorthWestern’s energy supply portfolio, additional flexible capacity resources are required to ensure compliance with RBC requirements.¹ Since 2008, 248 MWs nameplate capacity of VERs have interconnected to the transmission system and become a part of NorthWestern’s supply portfolio. Energy Supply had 147 MWs

¹ Refer to the Navigant study discussed in Chapter 3 and provided in Volume 2, Chapter 5.

nameplate capacity of VER on the system in 2008, and now has executed PPAs for a total of 555 MWs nameplate capacity of VER.² The total executed is equivalent to about 125 percent of NorthWestern’s retail supply minimum load of 443 MW.³

It is NorthWestern’s responsibility to balance essentially all of this retail variable generation on behalf of our retail customers. As a result, NorthWestern has had to use more and more of the flexibility inherent in our resource portfolio to meet this increasing balancing need on behalf of our retail customers. As the amount of VERs on NorthWestern’s system continues to grow, NorthWestern will need to contract for or acquire additional flexible resources to meet the requirements driven by the increased variability as supported by the VER study referred to previously.

Transmission Interconnections with Other BAs

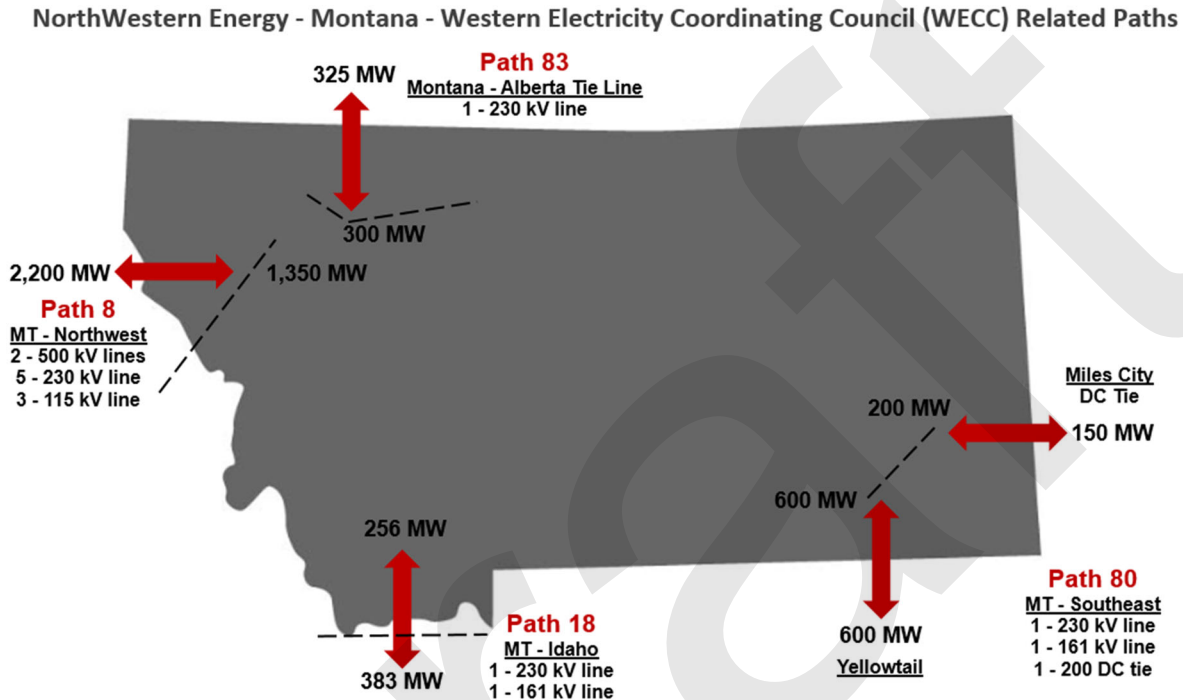
Figure 6-1 below depicts the amount of total transmission capacity (TTC) at the major interconnections of NorthWestern’s system with other transmission systems. The following are important points of emphasis.

- The largest interconnection is to the West on WECC Path 8.
- Path 8 provides access to the Mid-C Market through the BPA. It is the largest physical, electrical interconnection made up of multiple transmission lines.
- The other paths are not directly connected with the Mid-C Market and there are intermediate transmission systems with potentially significant transmission congestion issues associated with those paths.
- TTC is not ATC (the importance of this is explained below).

² There has been no variable generation interconnected since 2008 for use by FERC load customers or to be delivered to customers outside of NorthWestern’s BA.

³ Energy Supply minimum hourly load during 2017 was set on May 7.

Figure 6-1. NorthWestern Interconnections to WECC



Transmission System Challenges

As noted above, ATC is transmission capacity available after accounting for all party’s firm commitments. Table 6-1 shows the ATC effective as of June 1, 2019 on the same paths. As is indicated in the table, ATC is quite limited compared to TTC. At the most utilized interface with BPA, the import ATC is only 284 MWs compared with an import TTC of 863 MWs. The ATC is typically used during peak periods on an “as-available basis” and it can easily be “used up” during periods of peak demand. NorthWestern is not the only party that uses this capacity, which increases the risk of NorthWestern relying too heavily on the outside market to serve customers.

Table 6-1. Estimated Long Term Firm Path Availability

Estimated Long Term Firm ATC (MW) by Path - June 1, 2019				
Path	Export TTC	Export ATC	Import TTC	Import ATC
Path 8				
NWE - MT NW to Bonneville Power Administration Transmission	492	252	863	284
NWE - MT NW to Avista Corp Transmission	382	297	382	381
Path 18				
NWE - MT NW (Anaconda) to Brady (ID)	296	0	184	29
NWE - MT System to Jefferson (ID)	87	73	72	72
Path 80				
NWE - MT System to SE MT	600	600	600	507
Path 83				
NWE - MT NW (Great Falls) to NW MT (MT - Alberta Tie Line)	325	260	300	170

TTC = Total Transmission Capacity (designed and approved)
ATC = Available Transmission Capacity (accessible after obligations)

Conditions Experienced During Spring and Summer 2018

Conditions in NorthWestern’s BA during the spring and summer of 2018, highlighted significant concerns we have had for some time.

- The owned or controlled energy supply for NorthWestern’s retail customers is significantly deficit during peak hours.
- The transmission capacity from the energy markets is limited.

Figures 6-2 and 6-3 were developed using actual BA conditions during two days in 2018 and illustrate these concerns.

Figure 6-2 illustrates conditions on June 30, 2018. Elements of Figure 6-2 and salient circumstances specific to June 30, 2018 are described below.

1. The shaded gray area of the bar chart indicates the changes to peak load on NorthWestern's BA during the day. The maximum peak load of 1,297 MWs, which is a relatively low peak, occurred during the hour ending 18 on that day.
2. The blue portions of the bars indicate the total generation from the Colstrip Facility (Total Colstrip Generation – Net). During the peak, the Colstrip Facility output was about 450 MWs.⁴
3. The purple portions of the bars indicate the output from all of the wind generation in NorthWestern's BA area (Total BAA wind generation). Total BAA wind generation fluctuated throughout the day and peaked at about 206 MWs during the hour ending 1600.
4. The green line on the line graph represents the available import transmission capacity from BPA throughout the day (BPAT Scheduling ATC). Note there was no available transmission capacity to import electricity from BPA during most hours, including peak hours.
5. The red line on the line graph represents the net scheduled interchange. Scheduled **imports** into the BA are represented by negative numbers. Net imports to the BA were scheduled during all hours with a peak scheduled import of about 310 MWs near mid-day.

⁴ Colstrip Facility output was reduced at this time due to issues with some air emission control equipment. Those issues have since been remedied.

Figure 6-2. June 30, 2018 BA Needs and Scheduled Interchange

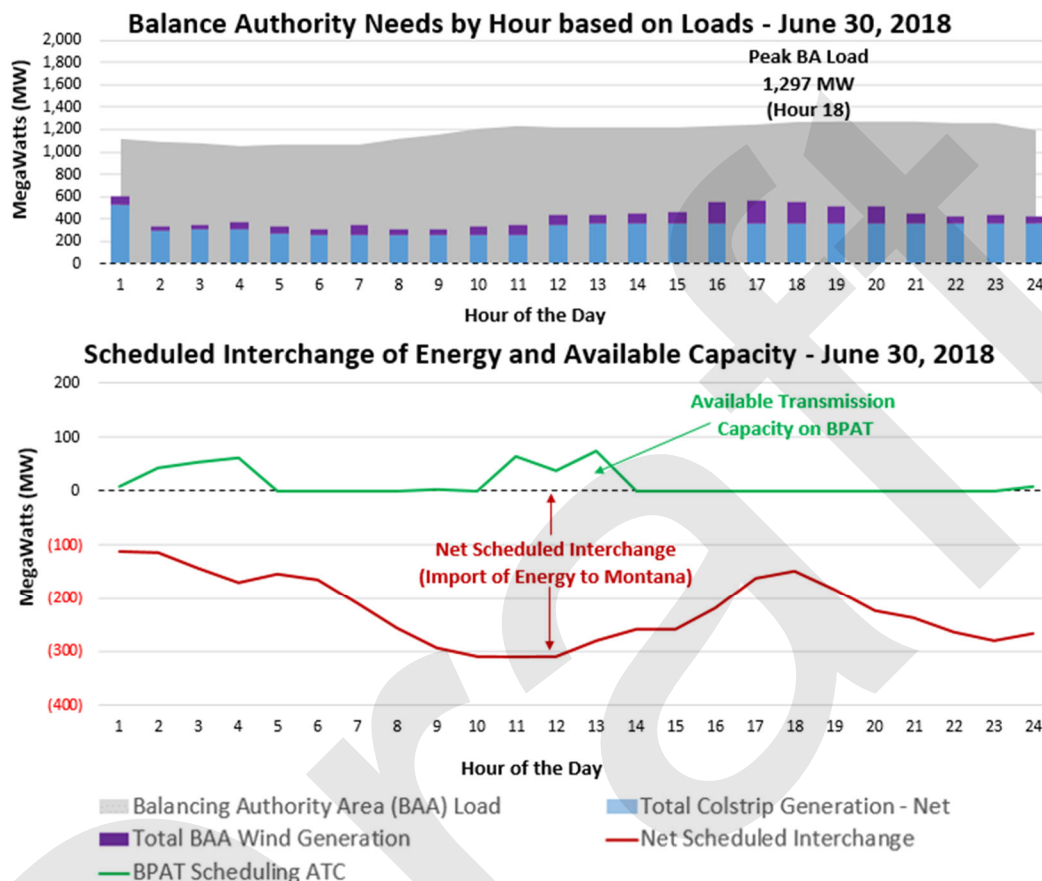


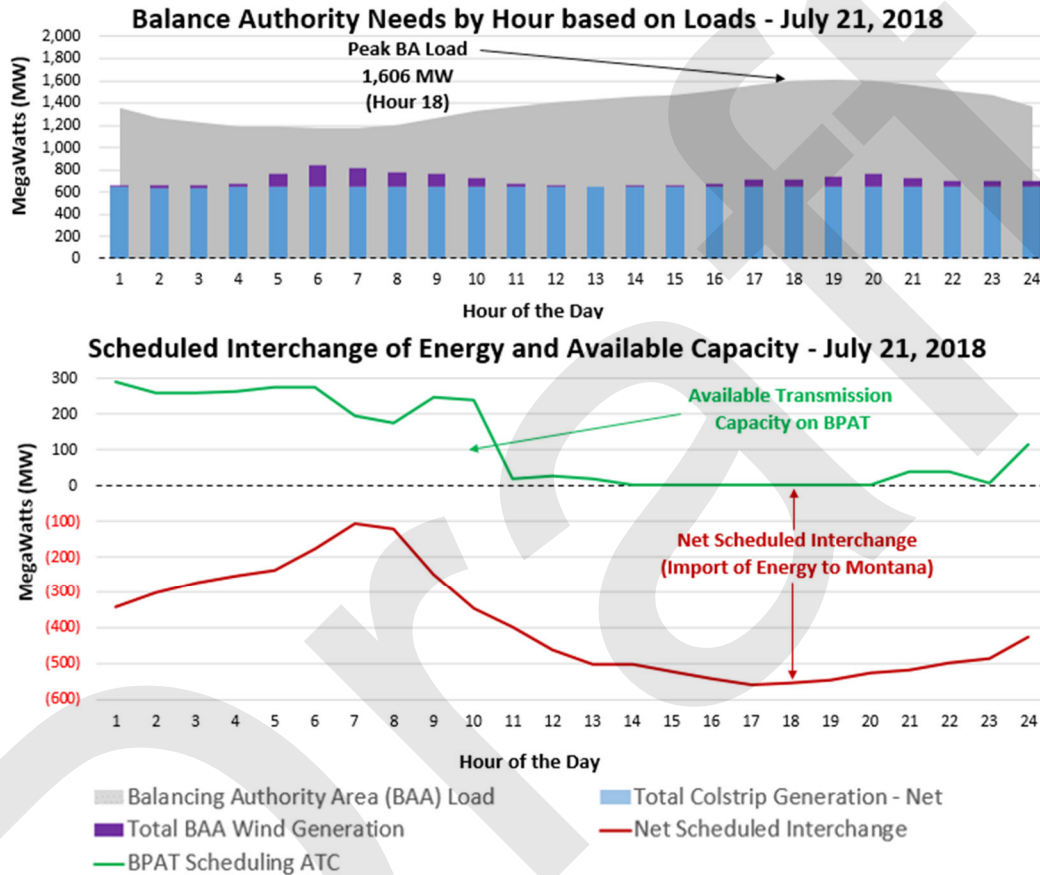
Figure 6-3 illustrates conditions on July 21, 2018. Elements of Figure 6-3 and salient circumstances specific to July 21, 2018 are described below. Note that the lines, bars and colors in Figure 6-3 have the same meanings as those in Figure 6-2. Their meanings are repeated however, in order to aid the reader’s understanding of Figure 6-3.

1. The shaded gray area of the bar chart indicates the changes to peak load on NorthWestern’s BA during the day. The maximum peak load of 1,606 MWs occurred during the hour ending 18, a 309 MW increase over the peak on June 30, 2018.

2. The blue portions of the bars indicate the total generation from the Colstrip Facility (Total Colstrip Generation – Net). During the peak, the Colstrip Facility output was about 650 MWs.⁵
3. The purple portions of the bars indicate the output from all of the wind generation in NorthWestern’s BA area (Total BAA wind generation). Total BAA wind generation fluctuated throughout the day, provided very little generation during some hours of the day, and peaked at about 114 MWs (out of a nameplate capacity of 338 MWs) during the peak hours of the day.
4. The green line on the line graph represents the available import transmission capacity from BPA throughout the day (BPAT Scheduling ATC). Note there was no available transmission capacity to import electricity from BPA during peak hours.
5. The red line on the line graph represents the net scheduled interchange. Scheduled **imports** into the BA are represented by negative numbers. Net imports to the BA were scheduled during all hours with a peak scheduled import of about 550 MWs coincident with the peak hours of the day; a 240 MW increase over the peak scheduled import on June 30, 2018.

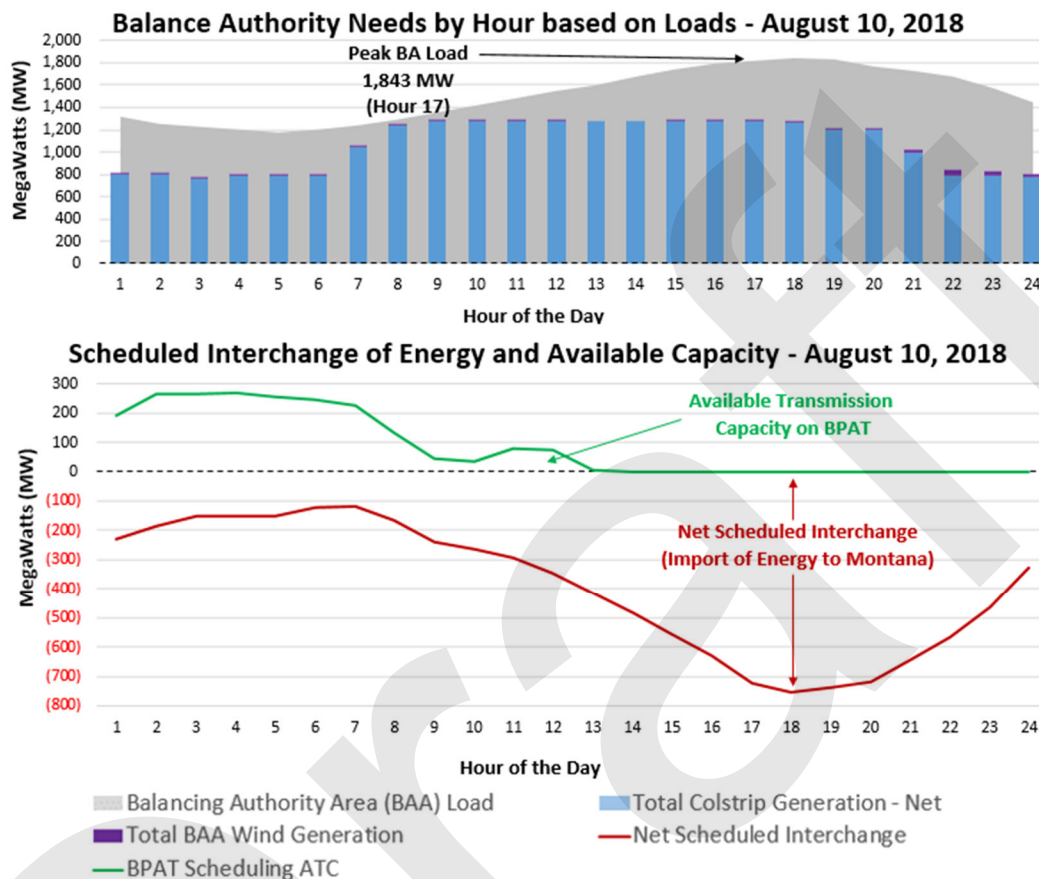
⁵ See footnote 4.

Figure 6-3. July 21, 2018 BA Needs and Scheduled Interchange



A new summer peak load record for NorthWestern’s BA was set on August 10, 2018 (this peak was ultimately eclipsed in February 2019). Conditions during the August 10, 2018 peak are illustrated in Figure 6-4.

Figure 6-4. August 10, 2018 BA Needs and Scheduled Interchange



Note that the lines, bars and colors in Figure 6-4 have the same meanings as those in Figures 6-2 and 6-3. While this is a notable day due to the magnitude of the peak load, close analysis of the situation is important for future transmission and energy supply resource planning.

1. As indicated by the gray area of the bar chart, the maximum peak load of 1,843 MWs on NorthWestern’s BA occurred during the hour ending 17. This peak load was a 546 MW increase over the peak on June 30 and a 237 MW increase over the peak on July 21, 2018.
2. The blue bars on the bar chart indicate the total generation from the Colstrip Facility

was about 1,270 MWs during most hours of the day including during peak hours.⁶

3. The purple bars on the bar chart indicate the total BAA wind generation was significantly below the nameplate capacity of 338 MWs most of the day and peaked at about 48 MWs during the hour ending 21.
4. The green line on the line graph indicates there was no available transmission capacity to import electricity from BPA during peak hours.
5. The red line on the line graph represents the net scheduled interchange. Scheduled **imports** into the BA are represented by negative numbers. Net imports to the BA were scheduled during all hours with a peak scheduled import of about 755 MWs coincident with the peak hours of the day; a 445 MW increase over the peak scheduled import on June 30 and a 205 MW increase over the peak scheduled import on July 21, 2018.

Not surprisingly, during the on-peak hours of the summer of 2018, the market price of energy at the Mid-C spiked dramatically illustrating the exposure to market volatility and the risk of being overly reliant on the market. See Figures 6-5 and 6-6.

⁶ Refer to footnote 4.

Figure 6-5. Mid-C Index Average On-Peak Prices

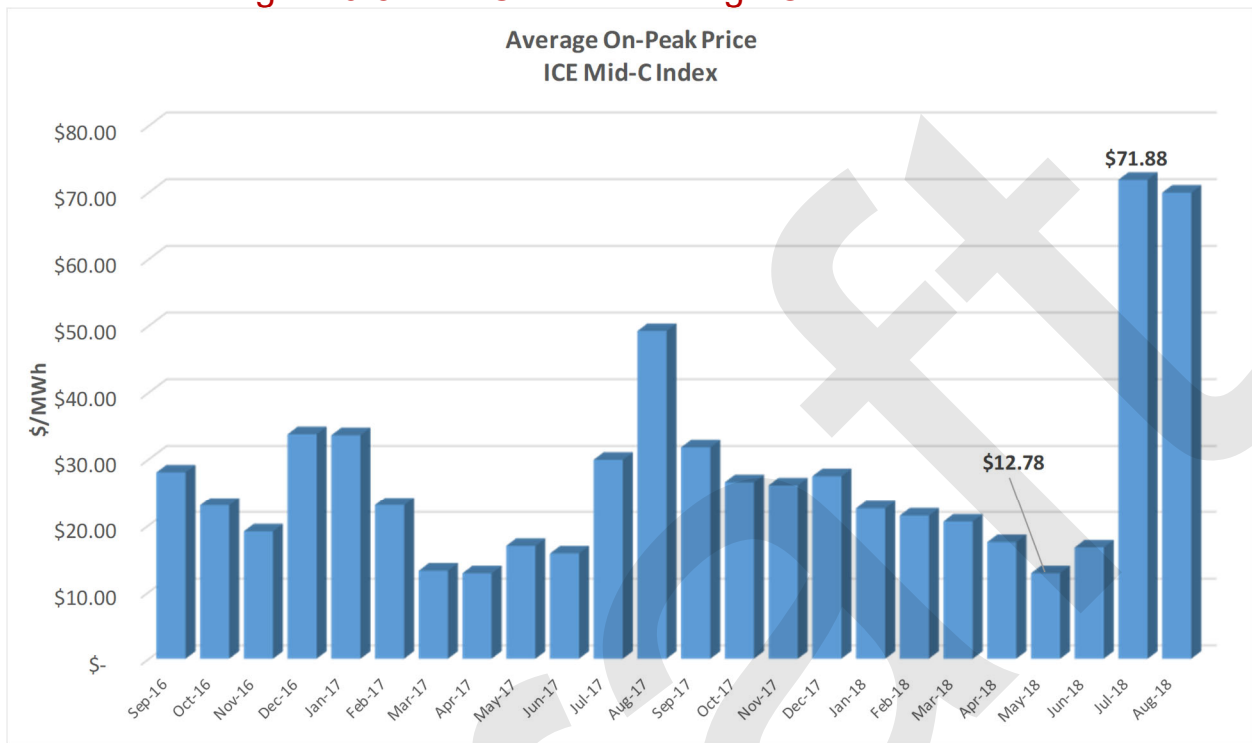
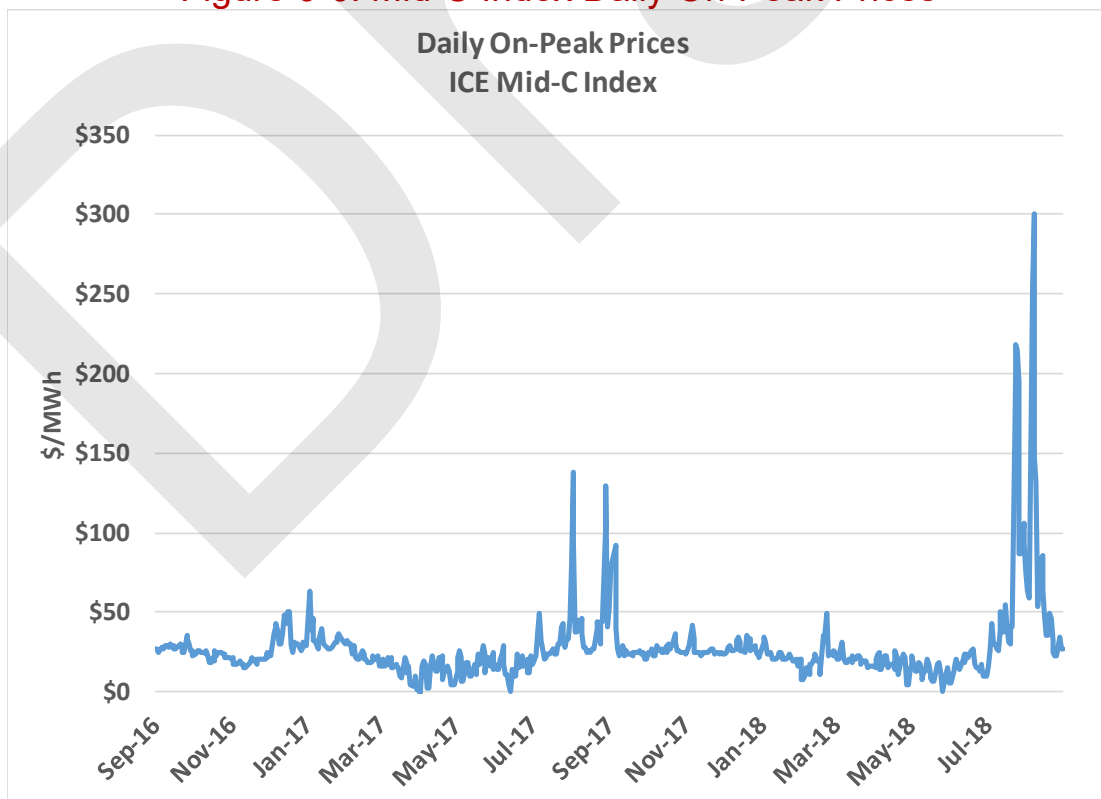


Figure 6-6. Mid-C Index Daily On-Peak Prices



There are several key takeaways from the discussion above about the conditions experienced during the spring and summer of 2018 which are summarized below.

- During peak/heavy load hours for the BA, NorthWestern relies heavily on imports into our system in order to meet customers' needs. Importantly, over 80 percent of the imports NorthWestern required to supply the very high loads on August 10th came from Path 8 (see Figure 6-1) and 100 percent of the imports NorthWestern required on August 11th came from Path 8.
- During peak/heavy load hours for the BA, the available transmission capacity at NorthWestern's interface with BPA is scarce and was routinely zero during peak hours.
 - While NorthWestern has other interties to other transmission systems, the interconnection to BPA is the largest and is a direct interconnection to the prevailing market in the Pacific Northwest, the Mid-C Market. Other routes to market are indirect, more costly and experience transmission congestion.
- The potential for BA load growth, (choice or non-retail customers) exceeds the projected growth of NorthWestern's bundled retail load due to the increase in load interconnection activity associated with blockchain and other data centers. This has the potential to further strain transmission import paths.
- During the days described above, part of the Colstrip facility's generation was reduced due to issues with some air emissions control equipment. Those issues have been remedied, however, the reductions foreshadow what will happen when Colstrip Units 1 & 2 cease operations in mid-2022.
- Wind generation did not significantly contribute to customers' needs during peak load hours.

- During the highest load hours on August 10, NorthWestern was importing nearly 400 MWs to serve retail customers. This represents over 30% of the retail load requirement.
- The market price for energy reacts to load serving requirements and transmission availability.
- Over reliance on market purchases from outside the BA can result in significant reliability issues compared to having access to flexible capacity resources within the BA.
- The status quo of significant reliance on the market for peaking supply needs will become increasingly risky as generation in Montana is shut down, loads increase, and existing generation resources are held in reserve in order to balance the significant growth of intermittent, variable energy resources.

NorthWestern's Natural Gas Transmission System

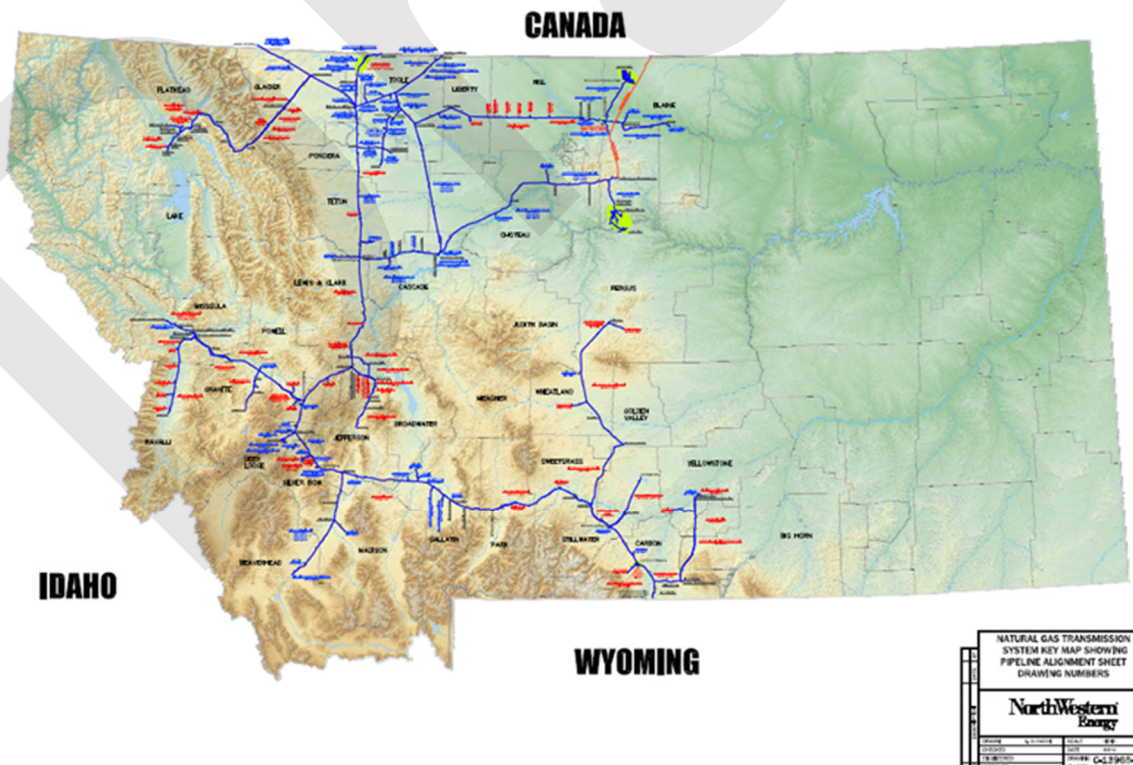
NorthWestern is including an analysis of the natural gas transmission system in this Plan to support modeling of cost effective natural gas resources.

NorthWestern's natural gas transmission system consists of more than 2,000 miles of pipeline and serves more than 153 city gate and meter stations where pressure is reduced to distribution level and measured. Pipeline diameter ranges from one inch to 24 inches. NorthWestern provides service to approximately 189,400 customers located in 117 Montana communities as well as to several smaller natural gas distribution companies that provide service to about 31,000 customers collectively. There are 92 individual compression units totaling almost 80,000 horsepower dedicated to our Montana gas transmission, storage and gathering operations. In addition, NorthWestern owns and

operates a pipeline which crosses into Canada through our wholly owned subsidiary, Canadian-Montana Pipeline Company (CMPL). This pipeline is critical because it enables us to receive gas from Canadian markets.

NorthWestern owns and operates three working natural gas storage fields in Montana: Dry Creek in southeast Montana with deliverability of about 44 million cubic feet per day (MMcfd); Cobb Storage north of Cut Bank with deliverability of about 115 MMcfd; and, Box Elder Storage near Havre with deliverability of about 10 MMcfd. This totals 169 MMcfd of peak deliverability in the gas storage system. There are 34 receipt points where gas enters our natural gas transmission system. In our three active storage reservoirs, we cycle about 10 billion cubic feet (Bcf) in and out of storage annually. Below is a high level gas transmission system map.

Figure 6-7. Montana Gas Transmission System



Peak deliverability needs occur during the heating season, generally November through March. Typically, the colder the weather, the higher the daily deliverability need.

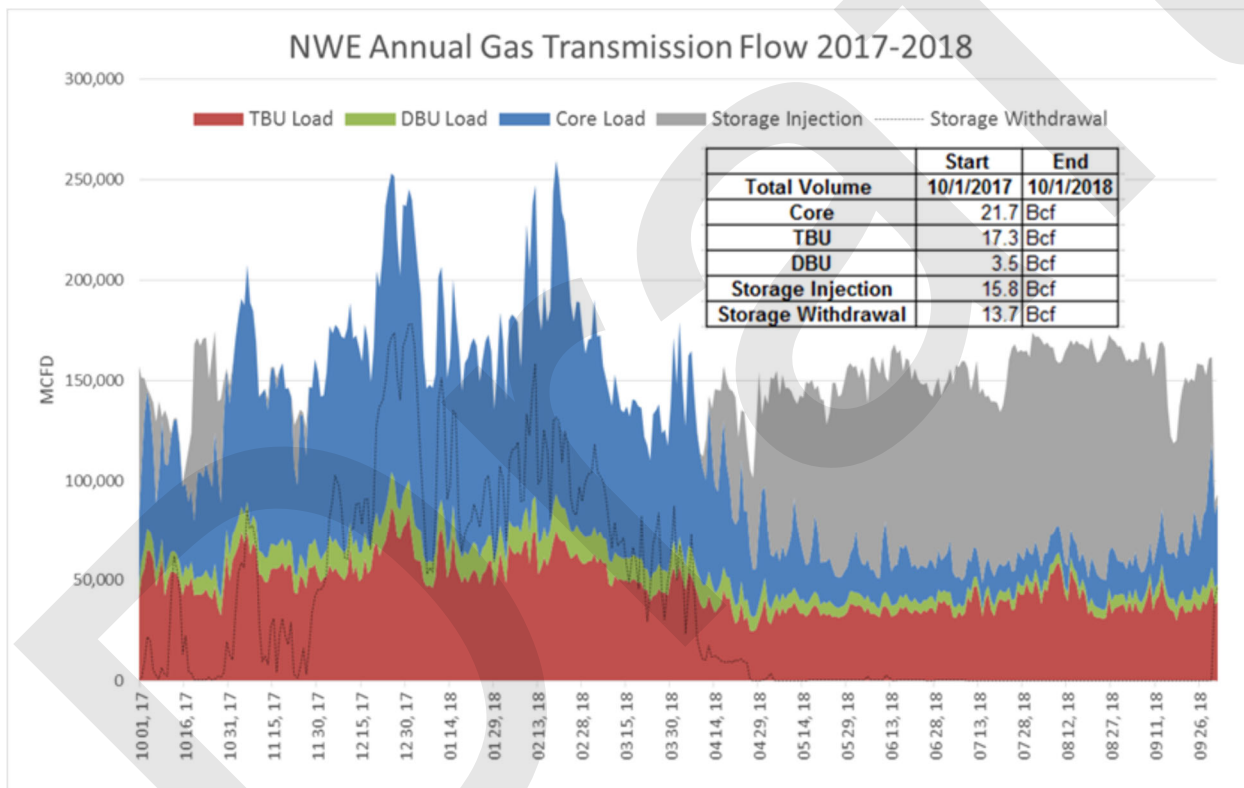
The natural gas supply provided to our customers during the heating season comes from three main sources and the transmission and storage system is key to delivering this gas: 1) flowing gas, which is produced in Montana and has no other place to flow except onto NorthWestern's system; 2) interconnect gas, which is produced outside of Montana but is delivered under contracts with interconnected pipelines to supply gas to NorthWestern's system; and 3) storage gas, which is brought onto the system in the "off season" and injected into NorthWestern's storage fields for use during the heating season.

Nearly one-half of transmission system deliverability comes from our storage reservoir capacity. NorthWestern also has interconnections with five other major pipelines: the TransCanada pipeline system at Carway northwest of Cut Bank via our CMPL subsidiary; Pine Cliff Energy northeast of Cut Bank at Aden; the TransGas system northeast of Havre (north flow only); Colorado Interstate Gas (CIG); and, WBI Energy in southeast Montana. These interconnections represent more than 39% of our peaking capability. However, the only interconnections that provide an effective interconnection to markets are at Carway to the north and CIG to the southeast. The balance of our peak day requirement comes from gas produced within Montana (flowing gas) with interconnections to our system. With on-system flowing gas depleting and heating loads growing, NorthWestern has been increasing deliverability at Carway and CIG through contracts with the upstream pipelines and infrastructure improvements on the NorthWestern system.

Currently, gas-fired generation on the system operates utilizing interruptible gas transportation arrangements. As a result, during the coldest days of the year, gas supply to electric generation is subject to curtailment.

The graphic below shows the overall usage of the gas transmission system for the October 2017 to October 2018 annual cycle. Usage of the system is high during both the heating season and the off-season because the system capacity in the off-season is used to refill storage for the next heating season.

Figure 6-8. Oct. 2017 to Oct. 2018 Gas Transmission Flow



NorthWestern plans carefully and the gas compression system includes a certain amount of redundancy; however, events out of our control can occur. These include much colder weather than design or expected conditions (or for a longer period of time) or unexpected equipment outages on our system or on adjacent systems delivering to our interconnections. As a result, beginning with the 2015-2016 heating season, NorthWestern developed a Gas

Curtailement Plan that allows us to interrupt gas use through careful curtailment of NorthWestern electric customers who are also served by NorthWestern’s natural gas system. For many years we have had curtailment plans on the electric system that are part of our overall planning and compliance requirements. It is prudent to also have a curtailment plan for gas operations in order to avoid more prolonged, difficult outages. We update the Gas Curtailement Plan as required and plan for its use in our operations during each heating season.

Similar to the electric transmission system, the gas transmission system was deregulated in the 1990s and as a result, NorthWestern provides transmission service to both bundled retail or “core” customers as well as “non-core” customers – those customers to whom NorthWestern provides transmission service, but is not responsible for providing natural gas supply.

Transmission Systems Summary

From a transmission perspective, NorthWestern must plan for both our retail customers and other customers served from the electric transmission system, but procure their supply from sources other than NorthWestern. Electric transmission capacity is critical for market access in order to purchase power when short and sell power when long however it is limited. During the most critical periods, NorthWestern relies heavily on electricity imports into our system in order to meet customers’ needs. The transmission system was constructed around, and is heavily reliant on, the generation resources in Montana and their locations in the BA. As a result, current reliability is based on access to imports, the 500 kV transmission system and an operating Colstrip generation facility. The retirement of Units 1 and 2 at Colstrip and potential outages or reductions of Units 3 and Unit 4, or other

state generation resources will severely impact NorthWestern's ability to serve our customers reliably. Absent significant flexible generation capacity additions in Montana, current transmission congestion and Montana's shift from an energy surplus state to an energy deficit state will result in unacceptable risk for Montana consumers.

CHAPTER 7

NEW RESOURCES

New Resources Overview

A key component of resource planning is the identification of the resources to consider for inclusion in the modeling analysis phase of the planning process. Reasonable estimates of resource costs and operating characteristics must be known to consider the resource for potential inclusion in the portfolio modeling analysis. In response to MPSC comments, NorthWestern retained HDR Engineering, Inc. (HDR) to prepare a RFI in order to solicit information regarding potentially available resource alternatives. NorthWestern also retained HDR to characterize the operational and cost attributes of various power generation and energy storage technologies.¹

Request for Information

NorthWestern retained HDR to solicit information regarding potentially available resources for potential inclusion in capacity planning as part of the 2019 Plan. The RFI was issued on July 9, 2018 to over 350 energy producers and consumers, including large industrial customers, developers, and utilities in the Pacific Northwest. A total of 19 responses were received with several respondents submitting multiple options.

Table 7-1 provides a summary of the responses received. Sections grayed out require a protective order and are confidential. The data presented is “as-reported” by the respondents (minimal evaluation/validation was completed).

¹ The HDR Study is provided in Volume II, Chapter 4.

Table 7-1. Summary of RFI Responses

Type	No. of Resp.	Scale			New / Existing	Ownership	PPA	
		Generation	Storage/Demand Side			Capital Costs	Capacity Cost	Energy Cost
-	(no.)	(Size)	(Size)	(Duration)	-	(\$/kW)	(\$/kW-yr)	(\$/MWh)
Energy Storage	5	-	250 kW to 400 MW	2 Min. to 9 hours	New	\$1,000 to \$8,000	-	-
Hydro	3	1.5 to 175 MW	-	-	Both	~\$3,100	TBD	TBD
Wind	4	35 to 400 MW	-	-	New	-	-	\$27 to \$36
Wind + Storage	1	[Redacted]						
Solar	1	[Redacted]						
Solar + Storage	5	[Redacted]						
CT/RICE	6	50 to 200 MW	-	-	New	\$500 to \$2,300	\$70 to \$250	\$3 to \$10
CT/RICE + Storage	2	[Redacted]						
Coal	2	[Redacted]						
DR/DSM	2	-	6 kW to 2 MW	2 to 4 hours	New		TBD	

Notes:

- (1) Data has been redacted to maintain confidentiality.
- (2) Data is "as-reported" by Respondents.
- (3) Responses included existing assets, project developments, and standalone technologies.
- (4) For cost reporting, "main" capacity cost presented; other costs may be applicable (e.g. operations and maintenance (O&M) costs).
- (5) PPA pricing assumes year 1 costs (escalation not evaluated in detail).
- (6) Production Tax Credit (PTC) and Investment Tax Credit (ITC) treatment not investigated.
- (7) Natural gas PPA energy costs do not include fuel costs (i.e. tolling PPA structure).

The RFI process validated HDR’s definitions for certain resources, and provided limited information on existing resources that could potentially be used to serve customers’ future resource needs. Additionally, the RFI identified some of the technologies that could appear in responses to future NorthWestern RFPs.

New Resources – New Build Costs

NorthWestern retained HDR to characterize the operational and cost attributes of various power generation and energy storage technologies considered in the 2019 plan. Several natural gas-fired generating technologies, renewable technologies and energy storage options were evaluated including reciprocating internal combustion engines (RICE), combustion turbines (CTs), combined cycle combustion turbines (CCCTs), pumped storage hydro, wind, solar PV, and battery energy storage resources. HDR also researched compressed air energy storage (CAES) and geothermal generation resources, but those were eliminated from consideration in the 2019 Plan due to higher cost. The evaluation of new-build resource costs involved analysis and contributions from HDR, Ascend Analytics, ETAC, and other sources.

Wind Resources

Overview

Wind power is a widely adopted generation technology. Improvements in efficiencies and the availability of Federal PTCs have been instrumental in the growth of wind energy. The current PTC is \$0.010/kWh over a 10-year time period for wind facilities commencing construction in 2019. PTCs are being phased out and this tax credit value represents a 60% reduction from the \$0.024/kWh PTC credit originally available under this program. The tax credit is not available for projects commencing construction after 2019. The phase out of the PTC is summarized in Table 7-2 below.

Table 7-2. Federal Wind PTC Phase-Out

Federal PTC Phase Out					
Year Construction Begins	2016	2017	2018	2019	Future
Wind PTC (\$/kWh)	\$0.024	\$0.019	\$0.014	\$0.010	\$0.000

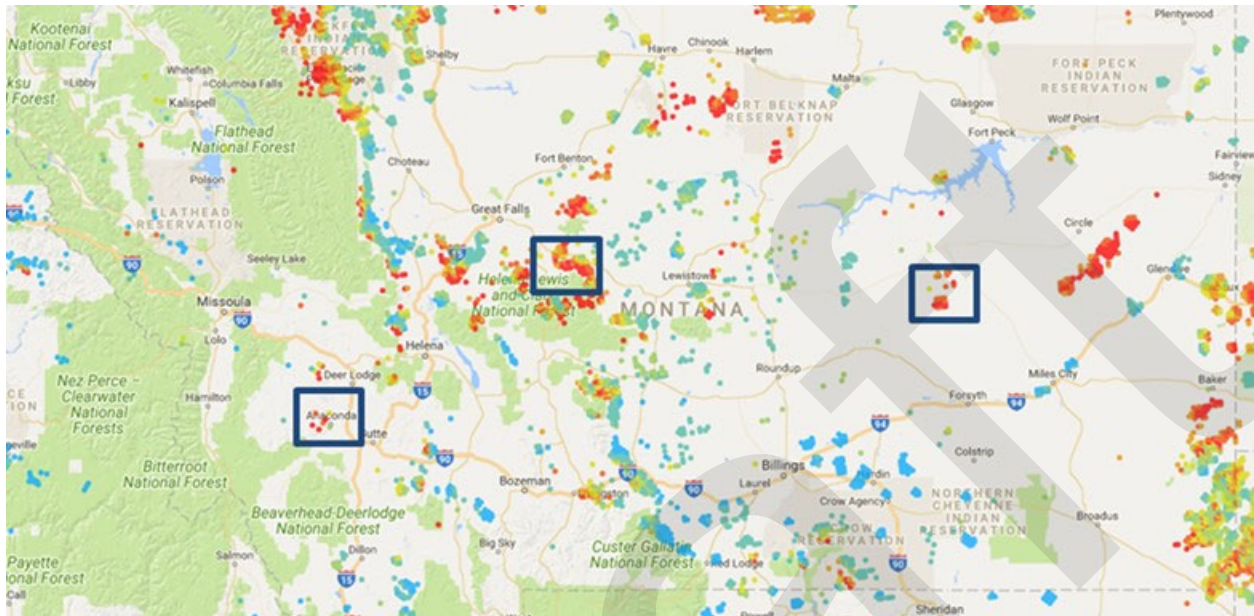
Performance

Wind generation projects are typically designed for a 20-year life, but well maintained turbines can last up to 25 years depending on the service conditions at the site and historical maintenance practices. Typical wind turbine sizes range from nominally 1.5 MWs to 5 MWs. For the 2019 Plan, the turbine design has a rated power of approximately 2.5 MWs and a hub height of 100 meters (m).

Wind turbine capacity is based largely on the length of the blades. Taller turbines are not only able to use longer blades for higher output capacity, but are also able to take advantage of the better wind speeds available at greater heights (while also considering related aviation regulations and requirements). An average net capacity factor (NCF) for a wind power facility is typically in the range of 25 to 50 percent depending on available wind energy within the region. The estimated NCF for the Montana locations shown in Figure 7.1 below, is 44.13% for Western Montana and 44.35% for Eastern Montana.

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Figure 7-1. Wind Location - Montana Analysis



NREL WIND Toolkit application was used to provide wind resource production data. The estimated power production at each site was developed using wind data at a 100 meter hub height and site-appropriate turbine power curves.

Cost Estimates

The project cost for a 100 MW, 40-turbine wind generation project located in western or eastern Montana was estimated by HDR to be \$1,410/kW. This conceptual engineering, procurement, and construction (EPC) cost includes the wind turbines, foundations, generator step-up transformers (GSUs), electrical systems up to the high side of the facility GSU, and instrumentation and controls. It was assumed that the turbines would be installed on land not owned by NorthWestern resulting in an assumed land lease cost, which is not included in the capital costs (typically included in O&M costs).

Fixed O&M costs for wind projects include staffing, major turbine parts, replacement parts and outsourced labor to perform major maintenance. Staffing for a proposed 100 MW wind power plant generally assumes the utilization of a remote monitoring/operating system. Typical staffing requirements are minimal and for the purpose of this analysis, include one salaried and two hourly staff. First year fixed O&M costs for a proxy 100 MW wind power plant are estimated at \$37.00/kW-yr. There are typically no variable O&M costs associated with wind power generation.

Currently, wind projects have a timeline of nominally two years from contractor notice-to-proceed (NTP) through commercial operation date (COD). The 2019 Plan assumes a COD of 2020 for a 100 MW utility-scale wind project.

Utility Scale Solar PV

Overview

Solar PV technology uses solar cells or PV arrays to convert light from the sun directly into electricity. PV cells are made of different semiconductor materials and come in many sizes, shapes, and ratings. Solar cells produce direct current (DC) electricity and therefore require a DC to alternating current (AC) converter to allow for grid connected installations.

Solar PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by the local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west and dual-axis trackers allow for modules to remain pointed directly at the sun throughout the day.

For the purposes of modeling solar PV in the 2019 Plan, NorthWestern assumes a 100 MW Solar PV facility with single-axis tracking configuration.

The Federal ITC has been instrumental in supporting the deployment and growth of solar energy in the U.S. The ITC currently offers a 30% tax credit towards the investment cost of solar systems. For a solar project to get the 30% ITC, it must begin construction by December 31, 2019, but it does not have to go into service until December 31, 2023. The percentage steps down to 26% and 22% for projects that start construction in 2020 in 2021, respectively. For all scenarios where a solar project receives greater than a 10% ITC, the project must be placed into service by December 31, 2023. A summary of the Federal ITC phase down is provided in Table 7-3.

Table 7-3. Federal ITC Phase-Down

Federal ITC Phase Down								
Year Construction Begins	2016	2017	2018	2019	2020	2021	2022	Future
Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%

In January 2018, the U.S. imposed a 30% tariff on imported crystalline-silicon solar cells and modules that went into effect February 7, 2018. The tariffs start at 30% of the cell price in 2018 and then gradually drop to 15% by February 7, 2021. Per SEIA, the 30% tariff can be expected to increase year 1 PV module prices by roughly \$0.10/W or \$100/kW.

Cost Estimates

A 100 MW solar PV installation would include approximately 40, 2.5 MW arrays each consisting of about 8,764 modules of 370 watt-peak-capacity (Wp). The land area required for this application could require about 400 to 700 acres.

The major components for the PV system include the PV modules/arrays, DC to AC converters/inverters, and mounting structures. An average capacity factor range for a solar power facility is typically in the range of 10 to 30 percent, with annual averages around 25 percent depending upon solar resources within the region. The estimated average annual capacity factors for the Montana sites were estimated using NREL’s PVSyst program, and determined by HDR to be 24.2% in western Montana and 24.5 % in eastern Montana.

HDR estimated the project cost for a solar plant located in both western and eastern Montana at nominally \$1,330/kW prior to implementation of the U.S. imposed tariff. Based upon the estimated impact of solar tariffs identified by the Solar Energy Industries Association (SEIA), costs could be expected to increase as a result of the tariff to \$1,430/kW.

First year fixed O&M costs for a 100 MW solar power plant are estimated to be \$21.60/kW-yr. There are typically no variable O&M costs associated with solar power generation. Typical staffing requirements are minimal and, for the purpose of this analysis, include one salaried and two hourly staff.

Battery Energy Storage

Overview

Grid-connected battery energy storage systems (BESS) are a maturing storage technology in the electric industry, with increasing commercial deployment. BESS technology can be used to help meet the overall electricity demands of an electric utility, help minimize peak demand, smooth load variations due to renewables integration, and help with local grid resilience and availability.

Lithium Ion (Li-ion) batteries utilize the exchange of lithium ions between electrodes to charge and discharge the battery. When the battery is in use and discharging the charged electrons move from the anode to the cathode and in the process, energize the connected circuit. Electrons flow in the reverse direction during a charge cycle when energy is drawn from the grid. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve applications. Additionally, compared to other BESS, the Li-ion technology provides the highest energy storage density resulting in its adoption in several different markets ranging from consumer electronics to transportation (electric vehicles) and power generation.

Vanadium redox flow batteries are based on the redox reaction between electrolytes in the system. There is significant interest in these flow batteries as they have a high cycle life, a large allowable operating temperature range, and longer storage durations. Vanadium redox systems consist of two liquid electrolytes in tanks (vanadium ions in different oxidation states) separated by a proton exchange membrane. The membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. The liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. A typical vanadium redox flow battery includes large electrolyte storage tanks and pumps, limiting this technology to certain applications.

Other battery storage technologies include sodium sulfur, lead-acid, zinc iron and zinc bromine flow technologies; however, Li-ion is the most prominent and widely used for utility scale BESS.

On February 15, 2018 FERC issued Order 841 that directs the operators of wholesale markets, RTOs and ISOs to develop market rules for energy storage to participate in wholesale energy, capacity, and ancillary service markets. The order essentially ensures that an energy storage resource can be dispatched and can set market clearing prices as both a buyer and seller. RTOs and ISOs have nine months to file tariffs that comply with the order and another year to implement the tariff provisions.

For the 2019 Plan, HDR evaluated a proxy 25 MW, 100 MWh (25 MWs for 4 hours = 100 MWh) BESS with one discharge cycle per day. The basis of capacity sizing was to provide NorthWestern with about 4 hours of dispatch capability enabling demand management/load shifting as well as provide temporary local service restoration during an outage.

Performance

HDR contacted numerous BESS companies² (aka “integrators”) for technical and commercial data. Technical information as well as experience, scope of supply, schedule of delivery, pricing and O&M details were solicited from the integrators that responded. Information received was specific to Li-ion technology, largely due to its prevalence in the industry. Some information was also gathered from vanadium redox flow battery integrators.

Major components of a BESS station include the battery containers, battery management system (BMS), power conversion system (PCS), enclosures, plant control system, cooling

² Greensmith Energy, ABB Inc., Renewable Energy Systems Americas Inc., S&C Electric Company, AES Energy Storage, Uni Energy Technologies, ViZn Energy Systems, Vinox Energy and Primus Power.

system, station load transformers, pad mounted medium/high voltage transformers, grid interconnection gear with metering, site utilities, foundations and plant fencing.

Table 7-4. Battery Energy Storage System Performance Data

Parameter / Technology	Lithium Ion	Vanadium Redox Flow
Capacity (MW)	25	25
Max Storage Limit (MWh)	100	100
Min Storage Limit (MWh)	2	2
Leakage Rate (%/hr)	0.05%	0.00%
Discharge Duration (hrs)	4	4
Recharge Time (hrs)	4	6.5
Round Trip Efficiency	85%	73%
Cycle Life (1 cycle/day 20 yrs)	7500	Over 7,500
Expected Annual Availability	96%	95%
Ancillary Service Capability	Reg up/down, spin/non-spin, reserve	Reg up/down, spin/non-spin, reserve

Table 7-4 summarizes estimated performance data for a typical 25 MW, 100 MWh BESS. An important consideration of BESS is round trip energy efficiency, which is the amount of AC energy the system can deliver relative to the amount of AC energy used by the system during the preceding charge. Losses experienced in the charge/discharge cycle include those from the PCS (inverters), heating and ventilation, control system, and auxiliary systems. Li-ion technology experiences degradation both in terms of capacity and round-trip efficiency with time due to a variety of factors including number of full charge/discharge cycles and environmental exposure. Typically, integrators employ augmentation strategies such as oversizing and/or periodic replacement, to ensure the grid connected BESS is supplying the necessary MWhrs and has the expected cycle life during the performance period. To meet electric utility customer needs, BESS integrators are willing to provide a guaranteed equipment life of about 20 years with an appropriate

augmentation strategy. Integrator strategies can be different and there are no set industry standards.

Vanadium redox flow batteries on the other hand, do not experience significant performance degradation due to the fact that the charged electrons are stored in the liquid (vanadium) form that has limited self-discharge characteristics and they also exhibit almost no degradation when the system is left discharged for long periods of time. However, given the large volume of solution that must be pumped, the auxiliary load and recharge time of a similarly sized flow battery system is higher when compared to the Li-ion technology.

Cost Estimates

The capital cost for an installed BESS includes the energy storage equipment, power conversion equipment, power control system, site utilities, electric scope to the high side of the GSU transformer, and installation costs.

For Li-Ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system includes internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For vanadium redox flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks, and container costs for the system along with associated cycling pumps and battery management controls. Each system requires a PCS to convert the produced DC power to AC power for ultimate grid utilization. The high level capital costs for a 25 MW/100 MWh Li-ion and vanadium redox flow BESS are estimated by HDR to be \$1,660/kW and \$1,700/kW, respectively.

The major component of the O&M cost for a Li-ion BESS system is related to energy and capacity augmentation. Augmentation maintains the BESS capability to serve the Owner’s requirement for the term of the agreement. The total annual augmentation costs are estimated based on 1 full cycle/day discharge rate and these costs are typically covered in the fixed O&M costs. Variable O&M costs include a discharging or cycling charge which is the variable component of the augmentation service agreement³. For the Li-ion BESS, conceptual first year fixed and variable O&M costs are estimated at \$39.61/kW-yr and \$7.00/MWh, respectively. No staffing costs are included and the variable O&M costs do not include electric purchases made to charge the batteries; charging cost can vary and is a function of energy costs at the time of charging.

For the vanadium redox flow BESS, conceptual first year fixed O&M costs are estimated at \$34.01/kW-yr⁴; there are typically no variable O&M costs associated with this technology.

The BESS integrator’s scope of supply typically includes most of the systems up to the inverter terminal where AC power is available to the GSU transformer. Accordingly, the BESS integrator can deliver the major systems within 9 months from NTP. Additional site engineering, foundation and substructure work, permitting, site utilities and utility interconnection work is generally completed by a general/EPC contractor. A typical 25 MW BESS project can be commissioned and in commercial operation within 14 months from NTP. The 2019 Plan assumes a COD of 2020 for the BESS project being modeled.

³ BESS O&M costs are sometimes expressed on a fixed O&M basis only.

⁴ This is the second year cost as the first year fixed O&M component is typically included in the project capital costs.

Pumped Hydropower Energy Storage

Overview

Pumped hydro energy storage (PHES) facilities store potential energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation. During periods of high electricity demand, electricity is generated by releasing the stored water through pump-turbines in the same manner as a conventional hydro station. In periods of low energy demand or low energy cost, historically during the night or weekends, water is pumped back into the upper reservoir.

Reversible pump-turbine/generator-motor assemblies can act as both pumps and turbines. Pumped storage stations are a net consumer of electricity, due to hydraulic and electrical losses incurred in the cycle of pumping from the lower reservoir to the upper reservoir. However, these plants typically perform well economically, capturing peak to off-peak energy price differentials, and providing ancillary services to support the overall electric grid. HDR evaluated a 500 MW, 4,500 MWh closed-loop PHES facility.

PHES Technology

The first U.S. pumped-storage plant was commissioned in 1929 to help balance the grid. Today, there are approximately 40 pumped storage projects operating in the U.S. and pumped energy storage is considered commercially available and mature as many plants were installed throughout the U.S. in the 1970's and 1980's. The generating equipment for the majority of the existing pumped storage plants in the U.S. is the reversible, single-stage Francis pump-turbine. The technology for single-stage units continues to advance, and a broad range of equipment configurations are available depending upon the available head, site layout, and desired operation. The technology is considered partially dispatchable

(limited based on reservoir volume) and generally possesses the operational flexibility to provide ancillary services.

Operational Considerations

A PHES facility requires specific geology, the potential to create two reservoirs, and acceptable topography. For the 2019 Plan, HDR selected a 500 MW PHES resource with 9 hours of dispatch capability located within NorthWestern’s Montana service territory.

A pumped storage project would typically be designed to have between 6 to 20 hours of hydraulic reservoir storage for operation at full generating capacity. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value. Existing pumped storage projects range in capacity from 9 to 2,700 MWs, and in available energy storage from 87 MWh to 370,000 MWh.

Water-to-wire efficiencies vary based on individual equipment designs, age of the project, and site hydraulics, and include the pump-turbine, generator-motor and transformer efficiencies. Water-to-wire efficiency is typically near 85 to 90 percent for pumping mode and approximately 88 percent for generating mode for fixed speed Francis pump-turbines, resulting in a turnaround or cycle efficiency of approximately 80 percent. Table 7-5 summarizes estimated performance data for a 500 MW-4,500 MWh PHES.

Table 7-5. PHES Performance Data

PHES Performance		
Net Capacity	MW	500
Max Storage Limit	MWh	4,500
Min Storage Limit	MWh	0
Discharge Duration	Hours	9
Net Turnaround Efficiency (1 st Year)	%	80

Cost Estimates

Conceptual EPC project costs for a 500 MW PHES project is estimated to range from \$1,700/kW to \$3,000/kW. The costs for a variable speed facility are expected to be approximately 20 percent greater than a single speed facility. No land procurement costs or Owner’s costs are included.

Land requirements for PHES can vary considerably depending upon the specific project. PHES land requirements can be over a few hundred acres for the reservoir alone. This is highly dependent on the depth of the reservoirs and the amount of storage capacity required to meet peak load periods.

Operations and maintenance costs for pumped energy storage have been estimated assuming a daily dispatch profile with approximately 9 hours of electric production daily. The estimated fixed and variable O&M costs are based on work for recent confidential pumped storage projects and comparable industry data. The first year fixed O&M cost is estimated to be \$14.55/kW-yr. A variable O&M cost of \$0.90/MWH is estimated as a function of the number of starts and stops per day. Additionally, the variable O&M costs associated with charging the upper reservoir can vary as a function of the energy costs at

the time of charging. The variable costs to charge the PHES system have not been included in the technology summary tables herein.

Thermal Resources

Overview

Thermal generation options considered in the 2019 Plan include CT and RICE technologies in either simple cycle or combined cycle configuration. Both are commercially proven and commonly implemented technologies for utility scale power generation applications using pipeline natural gas as the primary fuel source.

Simple cycle CT plants are generally used to supply power during periods of peak electric demand (peaking power) due to their low capital cost, short construction schedule, rapid response (e.g. quick start capability), and ability to operate cost effectively at low capacity factors compared to other power generation alternatives. Similar to simple cycle CT plants, simple cycle RICE installations are generally used to supply peaking power and to operate in load following scenarios. RICE technology is favorable for peaking applications due to its wide range of operability and rapid response capability. Generally, in utility power generation applications, RICE technology is smaller in scale and has better efficiency as compared to simple cycle CT technology. As compared to simple cycle CTs, RICE facilities are less susceptible to thermal performance variances due to changes in ambient conditions such as temperature and elevation.

A combined cycle facility involves the addition of a heat recovery steam generator (HRSG) to the exhaust of a CT or RICE unit for the conversion of exhaust heat into steam that drives a steam turbine generator. The result is a significant increase in thermal efficiency over that of a simple cycle configuration. As compared to simple cycle technologies, the

attributes of a combined cycle configuration include higher thermal efficiencies and less responsiveness in terms of starting and ramping, which make this technology more suitable for base load or intermediate load electrical supply.

Two of the simple cycle options considered in the Plan, the 50 MW aeroderivative CT and the 18 MW RICE, include the option to switch to a backup fuel in the event that the natural gas supply to the power generation facility is curtailed. Two different backup fuels were considered for these options: diesel fuel oil (FO) and liquefied natural gas (LNG). All other thermal options consider natural gas fuel only.

Simple Cycle Frame Combustion Turbine

This thermal resource option consists of a nominal 50 MW frame-type gas CT operating in a simple cycle configuration using natural gas fuel. This option includes the costs of an inlet air evaporative cooler and a selective catalytic reduction (SCR) system/oxidation catalyst to control emissions.

Simple Cycle Aeroderivative Combustion Turbine

Aeroderivative CTs differ from their heavy duty frame counterparts in that their designs are derived from aircraft engines. These CTs are especially well-suited for peaking applications given short start times and rapid ramp rates. Aeroderivative turbines are generally also able to handle a greater number of starts throughout their lifecycle. Two aeroderivative CTs are considered in this Plan.

The nominal 25 MW aeroderivative CT option is assumed to operate using only natural gas in simple cycle. The 50 MW aeroderivative CT option includes a base option and two derivatives. The base option is a single simple cycle aeroderivative CT operating on natural gas fuel only. One derivative assumes using diesel fuel as a backup fuel and the other

derivative assumes using LNG as a backup fuel. All aeroderivative options include costs for an inlet air evaporative cooler and exhaust SCR system/oxidation catalyst.

Adding diesel fuel backup capability involves the addition of a diesel storage tank, additional fuel forwarding pumps, and a modification of the CT to allow operation on both gaseous and liquid fuels. When operating on diesel fuel the CT will experience derated output and efficiency. Adding LNG backup capability involves the addition of a cryogenic tank, a re-gasifier which converts the LNG back to its original gaseous state, and a system for disposing of the LNG boil off during storage of the fuel. LNG is assumed to be trucked in therefore this configuration does not include a natural gas liquefaction plant. When operating on LNG supply, the turbine output and efficiency are similar to that when the CT is operating on natural gas. Equipping a facility with LNG storage tends to be more complicated and, as a result, has higher capital cost than equipping a facility with diesel fuel storage.

Combined Cycle Combustion Turbine

Two combined cycle options were considered in the Plan, a 150 MW option with supplemental duct firing and a 130 MW option without supplemental duct firing⁵. Both options consist of two nominal 50 MW frame CTs paired with dual pressure HRSG units. The HRSGs generate high and intermediate pressure steam using the hot exhaust gas from the CTs. This steam is fed to a single steam turbine generator to generate additional electrical output. The assumed configuration for these options includes an air cooled condenser (ACC) for thermal cycle heat rejection, inlet air evaporative coolers and SCR system/oxidation catalysts for emissions control.

⁵ Supplemental duct firing increases output due to additional steam generated from adding heat in the HRSGs. This configuration offers the added flexibility of being able to cycle the duct burners on and off.

Reciprocating Engines

Two RICE options were considered in this Plan. The first consists of a single nominal 18 MW RICE burning natural gas as a primary fuel. The engine is assumed to have an SCR system/oxidation catalysts for emissions reduction and fin-fan radiators for engine cooling. Both diesel fuel oil and LNG are assumed as backup fuels. The natural gas/diesel dual fuel RICE requires a liquid oil pilot system even when operating on natural gas fuel which increases cost.

The other option consists of a single 9 MW RICE operating on natural gas as the only fuel source. This engine is also assumed to be equipped with an SCR system/oxidation catalyst for emissions control and fin-fan radiators for engine cooling.

Dave Gates Generating Station – RICE Generation Addition

Overview

This resource option includes the addition of a nominal 50 MW, three-unit RICE generation facility at the DGGS. The modeled facility consists of three nominal 18 MW dual-fueled RICE burning natural gas as a primary fuel and ultra-low sulfur diesel (ULSD) as a backup fuel. The DGGS site is an attractive option to explore since it is an existing generation site adjacent to a NorthWestern transmission substation with significant existing infrastructure, an existing natural gas radial pipeline and associated metering station, an available unused generator step-up transformer and an existing large generator interconnection agreement (LGIA) with an additional available capacity of 63 MW.

Cost Estimates

The estimated total capital cost of this project is about \$1,482 per kW for a 2018 COD based on an Association for the Advancement of Cost Estimating (AACE) Class 3 cost

estimate for an EPC lump sum turnkey (LSTK) project. To be conservative, the estimate includes \$2.5M for upgrades to the existing natural gas delivery system and \$1.5M for electrical transmission interconnection work including possible relocation of transmission lines inside the DGGs facility. The necessity of the fuel delivery system upgrades and transmission interconnection work along with their associated costs would be further refined in a more detailed engineering design assessment and cost estimate. Conceptual first year fixed and variable O&M costs are estimated at \$10.29/kW-yr and \$6.57/MWh, respectively.

Other Generation Technologies

HDR also provided cost estimates for Compressed air energy storage (CAES) technology, and geothermal generation technology. However, these technologies are higher cost and were not selected in the automated resource selection process. Please refer to the full HDR study, which is included in Volume II, for a full description of these resource options and their costs.

Characteristics of Production and Summary of Costs

Summary Tables

Tables 7-6 and 7-7 below summarize the costs of the generation and storage technologies presented in this chapter. Table 7-6 shows the operating characteristics and costs for resources developed in Western Montana, and Table 7-7 shows the operating characteristics and costs for resources developed in Eastern Montana. Additionally, Figures 7-2 and 7-3 show the future cost curves for renewable and thermal resources, and Li-Ion battery storage technology. These cost curves were included in Automated

Resource Selection (ARS) so that future resource additions reflect these future cost curves.

The results of portfolio modeling results are presented in Chapter 10.

Table 7-6. New Resources Cost Summary for Western Montana

Western Montana (12/2018 Costs)	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Heat Rate - Winter (HHV)¹	Capital Cost²	Fixed O&M (Yr 1)	Variable O&M (Yr 1)
Technology	(Type)	(MW)	(Years)	(Btu/kWH)	(\$/kW)	(\$/kW-yr)	(\$/MWH)
Combustion Turbine - Dry Cooling							
Simple Cycle 1x0 CT - 50 MW Frame	NG	48.1	30	9,986	\$1,433	\$13.18	\$8.73
Simple Cycle 1x0 CT - 25 MW Aeroderivative	NG	28.1	30	9,902	\$1,659	\$20.42	\$5.58
Simple Cycle 1x0 CT - 50 MW Aeroderivative	NG	47.4	30	9,388	\$1,336	\$13.38	\$4.38
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG / Fuel Oil) ⁴	NG / Fuel Oil	47.2	30	9,426	\$1,491	\$13.81	\$5.13
Simple Cycle 1x0 CT - 50 MW Aeroderivative (NG/LNG) ⁴	NG / LNG	47.4	30	9,418	\$1,780	\$13.88	\$4.73
Combined Cycle 2x1 CT - Frame/Industrial CT	NG	133.3	30	7,210	\$1,323	\$25.75	\$6.30
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Unfire	NG	133.3	30	7,221	\$1,385	\$25.85	\$6.31
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Fired	NG	151.9	30	7,533	\$1,215	\$22.69	\$5.55
Reciprocating Internal Combustion Engine							
DGGS Buildout 3x0 RICE - 18 MW Class (NG / Fuel Oil) ^{4,5}	NG / Fuel Oil	50.0	30	8,503	\$1,482	\$10.29	\$6.57
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	8,329	\$1,833	\$23.26	\$4.68
Simple Cycle 1x0 RICE - 18 MW Class NG Only (NG / LNG) ⁴	NG / LNG	19.4	30	8,357	\$2,149	\$23.62	\$4.99
Simple Cycle 1x0 RICE - 18 MW Dual Fuel (NG / Fuel Oil) ⁴	NG / Fuel Oil	17.4	30	8,503	\$2,075	\$29.70	\$6.57
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	8,103	\$2,324	\$54.62	\$4.55
Wind Energy							
Wind Energy	N/A	105.0	25	N/A	\$1,410	\$37.00	N/A
Solar Photovoltaic (PV)							
Solar PV - Single Axis Tracking	N/A	105.0	20	N/A	\$1,330	\$21.60	N/A
Geothermal							
Geothermal - Flash Steam	N/A	21.0	30	1,000	\$2,800	\$123.98	\$9.88
Pumped Hydro Energy Storage (PHES)							
PHES - Closed Loop (9 Hour)	Elec. Grid	525.0	30	N/A	\$1,700-\$3,000	\$14.55	\$0.90
Compressed Air Energy Storage (CAES)							
CAES - Diabatic (8 Hour)	Elec. Grid / NG	105.0	30	4,500	\$1,500-\$2,300	\$15.27	\$8.53
Battery Energy Storage System (BESS)							
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	N/A	\$1,660	\$39.61	\$7.00
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	N/A	\$1,700	\$34.01	N/A

¹ Thermal heat rates are presented on a higher heating value (HHV) basis.

² \$/kW capital cost metrics divide estimated project costs by the net winter output for a given technology.

³ Capacity factors for dispatchable technologies assumed in order to develop O&M costs.

⁴ Dual fuel performance and costs are presented as a blend of NG and alternative fuel (NG or FO) operations (1,034 hours on NG and 263 hours on alternate fuel).

⁵ Costs discounted to 2018 dollars to be comparable with other resources in the table.

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Table 7-7. New Resources Cost Summary for Eastern Montana

Eastern Montana (\$2018)	Fuel	Nameplate Capacity (Nominal)	Design Life	Net Output - Winter	Net Heat Rate - Winter (HHV)	Capital Cost	Fixed O&M (Yr 1)	Variable O&M (Yr 1)
Technology	(Type)	(MW)	(Years)	(MW)	(Btu/kWH)	(\$/kW)	(\$/kW-yr)	(\$/MWH)
Combustion Turbine - Dry Cooling								
Simple Cycle 1x0 CT - 50 MW Frame	NG	51.4	30	48.9	9,970	\$1,361	\$12.52	\$8.30
Simple Cycle 1x0 CT - 25 MW Aero derivative	NG	30.5	30	29.1	9,921	\$1,547	\$19.03	\$5.37
Simple Cycle 1x0 CT - 50 MW Aero derivative	NG	49.6	30	47.3	9,369	\$1,276	\$12.78	\$4.05
Simple Cycle 1x0 CT - 50 MW Aero derivative (NG / Fuel Oil)	NG / Fuel Oil	49.4	30	47.1	9,407	\$1,425	\$13.19	\$4.72
Simple Cycle 1x0 CT - 50 MW Aero derivative (NG/LNG)	NG / LNG	49.6	30	47.3	9,399	\$1,700	\$13.26	\$4.38
Combined Cycle 2x1 CT - Frame/Industrial CT	NG	140.2	30	133.5	7,213	\$1,259	\$24.49	\$5.99
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Unfired	NG	140.6	30	133.9	7,192	\$1,312	\$24.50	\$6.00
Combined Cycle 2x1 CT - Frame/Industrial CT w/ DB - Fired	NG	159.6	30	152.0	7,530	\$1,157	\$21.60	\$5.31
Reciprocating Internal Combustion Engine								
Simple Cycle 1x0 RICE - 18 MW Class NG Only	NG	19.4	30	18.5	8,318	\$1,833	\$23.07	\$4.64
Simple Cycle 1x0 RICE - 18 MW Class NG Only (NG / LNG)	NG / LNG	19.4	30	18.5	8,356	\$2,149	\$23.43	\$4.99
Simple Cycle 1x0 RICE - 18 MW Dual Fuel (NG / Fuel Oil)	NG / Fuel Oil	17.4	30	16.5	8,545	\$2,075	\$29.45	\$6.53
Simple Cycle 1x0 RICE - 9 MW Class NG Only	NG	9.6	30	9.2	8,103	\$2,306	\$54.20	\$4.52
Wind Energy								
Wind Energy	N/A	105.0	25	100.0	N/A	\$1,410	\$37.00	N/A
Solar Photovoltaic (PV)								
Solar PV - Single Axis Tracking	N/A	105.0	20	100.0	N/A	\$1,330	\$21.60	N/A
Geothermal								
Geothermal - Flash Steam	N/A	21.0	30	20.0	1,000	\$2,800	\$123.98	\$9.88
Pumped Hydro Energy Storage (PHES)								
PHES - Closed Loop (9 Hour)	Elec. Grid	525.0	30	500.0	N/A	\$1,700-\$3,000	\$14.55	\$0.90
Compressed Air Energy Storage (CAES)								
CAES - Diabatic (8 Hour)	Elec. Grid / NG	105.0	30	100.0	4,500	\$1,500-\$2,300	\$15.27	\$8.53
Battery Energy Storage System (BESS)								
BESS - Lithium Ion (4 Hour)	N/A	26.3	20	25.0	N/A	\$1,660	\$39.61	\$7.00
BESS - Vanadium Flow (4 Hour)	N/A	26.3	20	25.0	N/A	\$1,700	\$34.01	N/A

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Figure 7-2. New Resources Cost Trends for Renewables and Batteries

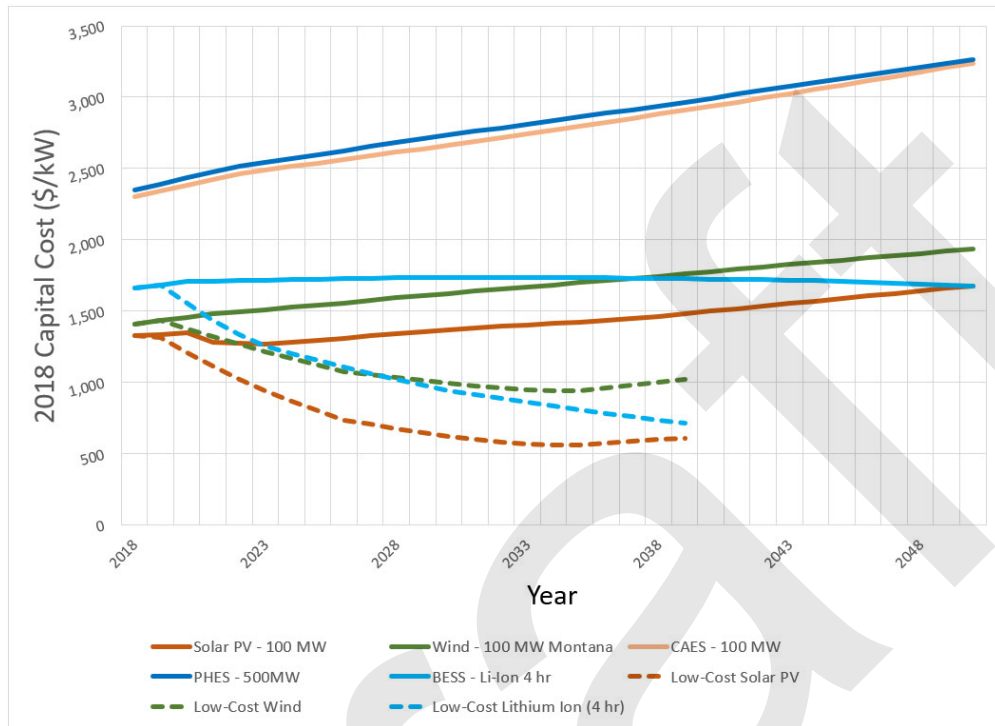
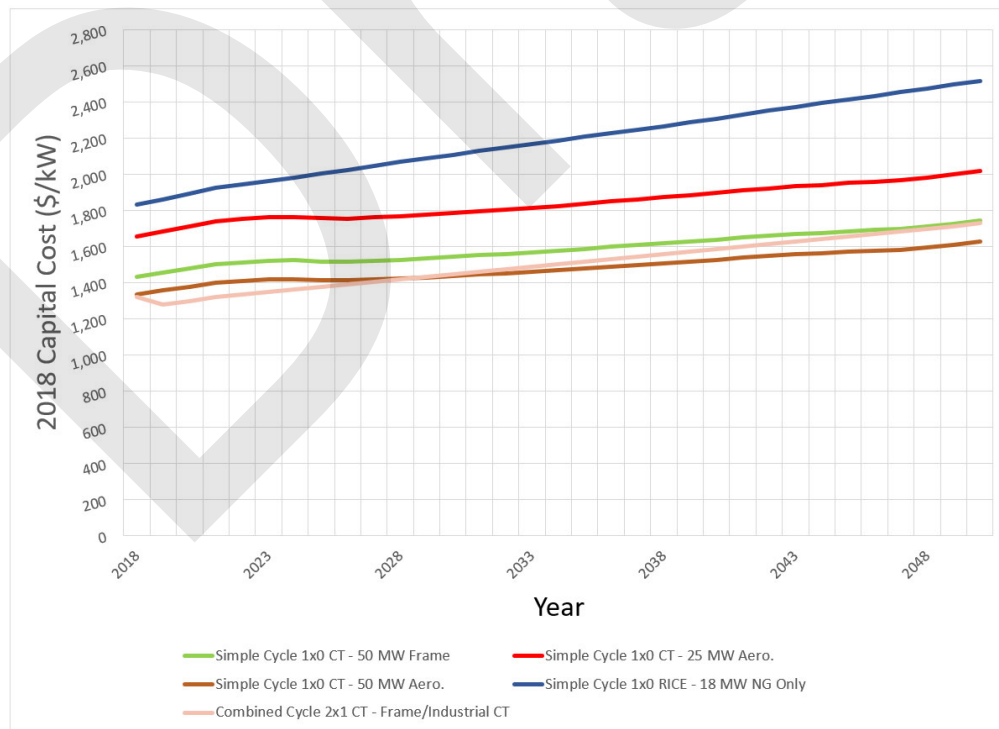


Figure 7-3. New Resources Cost Trends for Thermal Resources



CHAPTER 8

EMERGING TECHNOLOGIES

NorthWestern's Distribution System

Overview

This chapter includes a discussion of technologies that will impact NorthWestern's future energy supply, and explores resource options that may have the potential to serve our customers' future resource needs. The chapter includes a discussion of smart grid technologies, smart metering infrastructure, NorthWestern supported solar PV projects, and new technologies for energy storage and generation.

Building the Foundation for the Future

NorthWestern is investing in building a smarter energy infrastructure. In 2013 we began the Distribution System Infrastructure Project (DSIP). DSIP helps position NorthWestern so we can adopt new, cost-effective, energy technologies by modernizing aging infrastructure, enhancing reliability and providing margin (i.e. additional capacity) for the distribution system. Most of DSIP was completed in 2017; however, part of DSIP includes extending our communication network and establishing the groundwork for automating principal distribution substations and this portion of the project will conclude in 2020.

Automation is a key component of a smarter energy infrastructure and of participation in organized markets such as the EIM. Our work includes expanding NorthWestern's wireless communication system using two newly purchased communication radio spectrums along with our existing backbone fiber optic and microwave communication

system. We've established a separate distribution communications network and it is now routine business practice to extend our communications network during capital projects that require the use of this network. Presently this network is being used by our "pilot" distribution SCADA¹ system to communicate with electronic relays and reclosers² that are being added or upgraded within distribution substations. In 2019, the "pilot" SCADA will transition to a new Advanced Distribution Management System (ADMS). ADMS will assist our distribution system operators, engineers, technicians and managers in optimizing the efficiency, reliability, and overall performance of the electric distribution system.

Smart Metering Infrastructure

Today, our smart metering network is used for automated meter reading, automated outage alarms integrated into the ADMS, and automated electric meter disconnects/reconnects. Additionally, NorthWestern has deployed a new version of the smart metering field area network which provides the foundation for incorporating multiple networks, applications, and devices within a single, unified communications architecture. This communication network extends to each customer's meter and can extend to Building Management Systems, Home Area Networks, and other intelligent devices such as load control modules.

Demand Response

NorthWestern continues to explore demand response technology to determine how it may best fit with customer needs and energy capacity requirements. Initially, NorthWestern explored demand response during the Pacific Northwest Smart Grid Demonstration Project

¹ SCADA is an acronym for supervisory control and data acquisition, a computer system for gathering and analyzing real time data.

² A class of switchgear designed for use on electric networks to detect and interrupt momentary faults.

with residential customers and a commercial customer. In residential homes, quarterly events were tested that involved multiple phases of customer load reduction. These events allowed customers the freedom of participating in a demand response event or opting out using their home equipment. The software used during the demonstration project calculated the load reduction capability based on customer supplied data that was gathered at the initial phase of the project.

The commercial application was to be a test of demand response during a peak pricing event. For this test, a pricing signal was to be sent to a building automation control system and the building system was to respond according to a predetermined load curtailment schedule to reduce load based on price. Unfortunately, the software was never fully developed due to time and cost constraints and the commercial system was never tested.

We are also investigating the use of advanced software applications within our smart metering network that include distributed intelligence which can be used to segregate meters to enable surgical reductions in demand based on individual customer profiles and their ability to shed load. This software can allow dispatch of multiple demand response programs including direct load control and voluntary pricing programs. Additionally, optimization and dispatch of complex portfolios including traditional and renewable distributed generation, storage, and curtailable load are being investigated along with forecasting and dispatching of distributed energy resources to support load relief on our distribution grid.

Distributed Energy Resources (DERs)

The ADMS software also has a module with the capability to integrate power distribution networks by connecting DERs like private solar and battery energy storage. NorthWestern's current plan is to employ the ADMS DER module within the next five

years. This future application will help our distribution network keep the grid balanced and optimized in real-time while maintaining system reliability and power quality

Review of NorthWestern’s Technology Projects

NorthWestern continues to develop or co-develop pilot scale projects in order to investigate and demonstrate various aspects of how solar PV and battery storage can be used on our distribution system. The Community Sustainable Energy Working Group (CSEWG) which is comprised of a diverse group of local and state government representatives, environmental and customer advocates, and local renewable developers, assisted in selecting project technologies and locations. With assistance from the Smart Electric Power Alliance (formerly known as the Solar Electric Power Association) four pilot projects focused on customer enabling initiatives and grid integrated technologies were selected.

These projects are designed to create opportunities for consumers to become familiar with integrated energy grid technologies and become more engaged with how they consume energy. The projects are truly “smart community” projects and provide opportunities to work with communities as partners to help meet their goals while generating hands-on knowledge and data for NorthWestern’s system planners and others. The information is being used to analyze possible sustainable business models for adding renewable technology to our energy grid.

A summary each project is provided in Table 8-1. Following the table are a brief description and status of each project. Two of the four projects, located in Deer Lodge and Bozeman, are installed and operational. The remaining two projects will be installed in Missoula and Helena in the next two to three years. These projects represent a small part of NorthWestern’s efforts to develop additional renewable energy in Montana.

Table 8-1. NorthWestern Supported Solar Projects

Project	Location	Target Customers	Description	Technologies Deployed	Desired Learnings
Deer Lodge Microgrid	Beck Hill (Approx. 7 miles N. of Deer Lodge, MT)	Customers with rural reliability issues	~160 kWh of battery storage paired with 40 kW of Solar	Communications	Value of energy storage in rural applications
				Lead acid battery storage	Storage optimization
				DC coupled solar	Benefits of solar in microgrid applications
				AC coupled solar (string inverter)	Development cost models
				AC coupled solar (Micro-inverters)	Microgrid controls including ancillary services provided by energy storage
				Electronic reclosers	
Bozeman Solar Project	Bozeman Water Treatment Facility	Diversity of residential, commercial, & industrial customers	380 kW PV array with smart inverters and 60 volunteer customers with advanced metering	Utility-scale solar	Peak shaving
				Smart inverters	MSU educational component
				Advanced Metering Infrastructure (AMI)	Community solar rate modeling
				Virtual net-metering	Development process/cost
				West facing panels	Integrating solar to grid
					Distribution management system
Missoula Solar Project	Schools in Missoula	School property: Big Sky, Sentinel, Hellgate, Willard	Multiple size solar PV and energy storage	Solar PV	Identification of customers and data collection
				Automated metering	Establishing school & utility solar partnerships
				Energy storage	Student involvement & education
				EDI dashboard - usage	Scalability
Helena Solar Project	Existing footprint of Smart Grid Demonstration Project, 6th ward	Expanded footprint focused on low-income	Utility owned / controlled solar paired with AMI, advanced inverters, and energy storage	Advanced inverters	Conservation savings through Volt/VAR
				Solar PV	Ride through capabilities of inverters
				AMI	Value & use of energy storage at different points on the grid
				Energy storage	Test utility owned distributed solar / inverters
				Communication	Tipping point of circuit capacity
	Customer interest & engagement				

Deer Lodge (Beck Hill) Microgrid Project

NorthWestern Energy developed and commissioned this project in 2015 in order to provide data on how small microgrids can increase reliability, better manage load, defer asset acquisition and provide greater system efficiency. The project uses a 40-kilowatt solar system and an 80-kilowatt battery bank to provide electricity for seventeen customers for two to four hours during a feeder outage. The project is helping us further assess the potential of solar generation across our Montana electric service territory. Additionally, the project has provided an opportunity for Montana State University seniors to engage in a renewable energy project and help evaluate inverter improvements.

NorthWestern provided approximately \$600,000 for this project which is expected to have a lifespan of five to 10 years

Figure 8-1. Deer Lodge Solar PV Inverters and Battery Racks

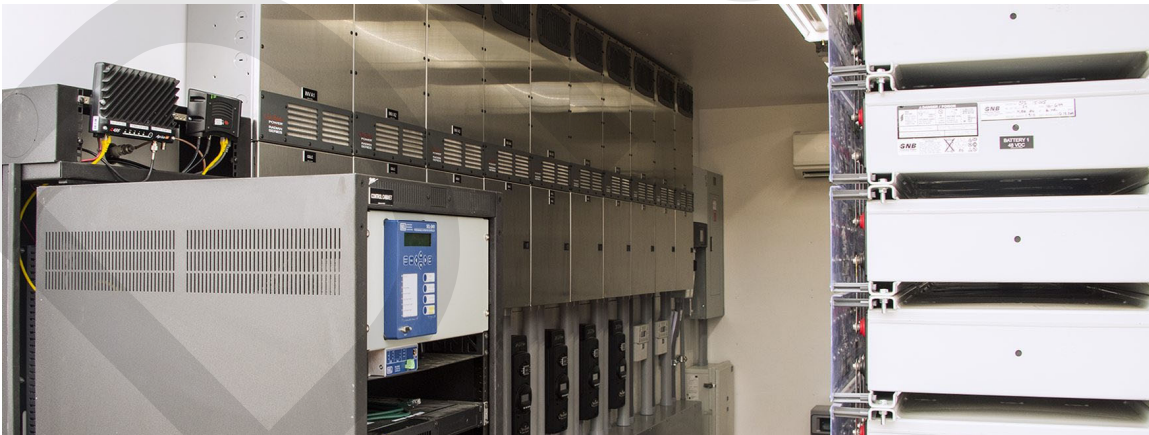
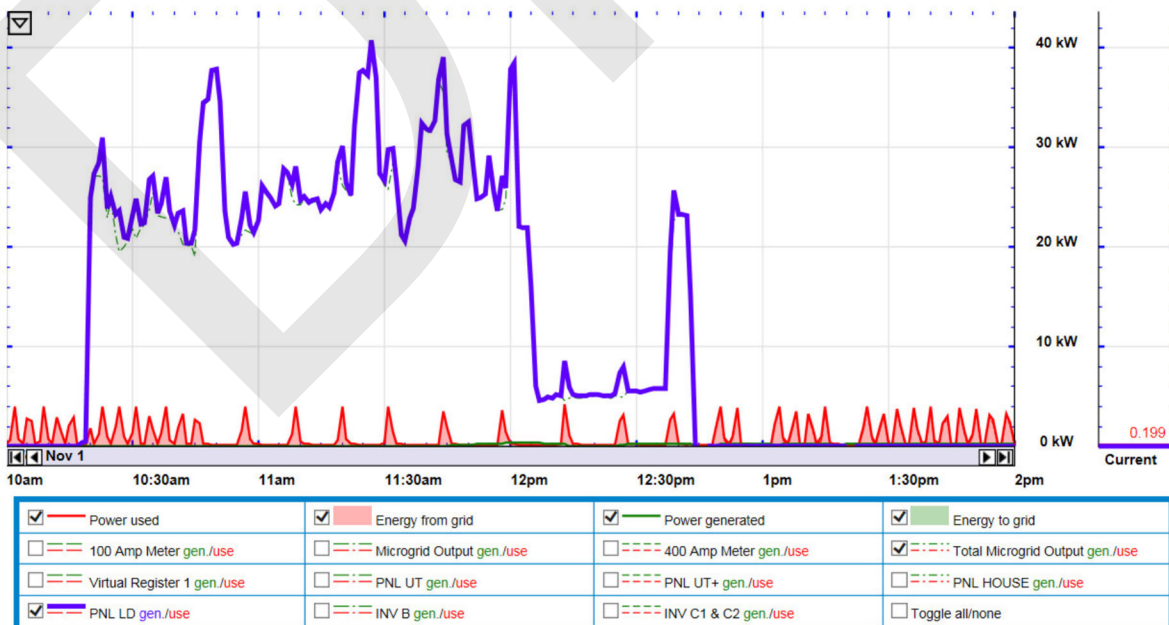


Figure 8-2. Deer Lodge Microgrid Solar PV Array and Containers



Figure 8-3 illustrates the microgrid production on November 1, 2017 during a distribution feeder outage of approximately 3.5 hours.

Figure 8-3. Deer Lodge Solar Microgrid Operation During Feeder Outage



Bozeman Solar Project

The Bozeman Solar Project was commissioned in 2016 and is a pilot scale community solar project for the City of Bozeman. The project is a partnership between three entities, NorthWestern Energy, the City of Bozeman and Montana State University.

This solar project will generate about 533,000 kilowatt-hours of energy per year. Along with solar PV panels and smart inverters, the project uses 40 residential and 20 commercial advanced smart meters to help the project partners better understand how solar power aligns with customer needs.

NorthWestern's goals of providing our customers reliable energy service from a diversified portfolio and to work with our customers to develop solutions to meet their particular needs is demonstrated in the Bozeman Solar Project. This project will provide valuable data about community solar models and will also help the City of Bozeman achieve its climate action plan goals and plan for future renewable energy projects.

NorthWestern committed \$1 million for the construction and operation of the project. The City of Bozeman has agreed to provide use of the land but has no additional financial responsibility tied to the project. MSU is helping with research tied to the five-year pilot through 2 senior design projects. See Figures 8-4 through 8-6.

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Figure 8-4. Bozeman Solar Microgrid Output Profile

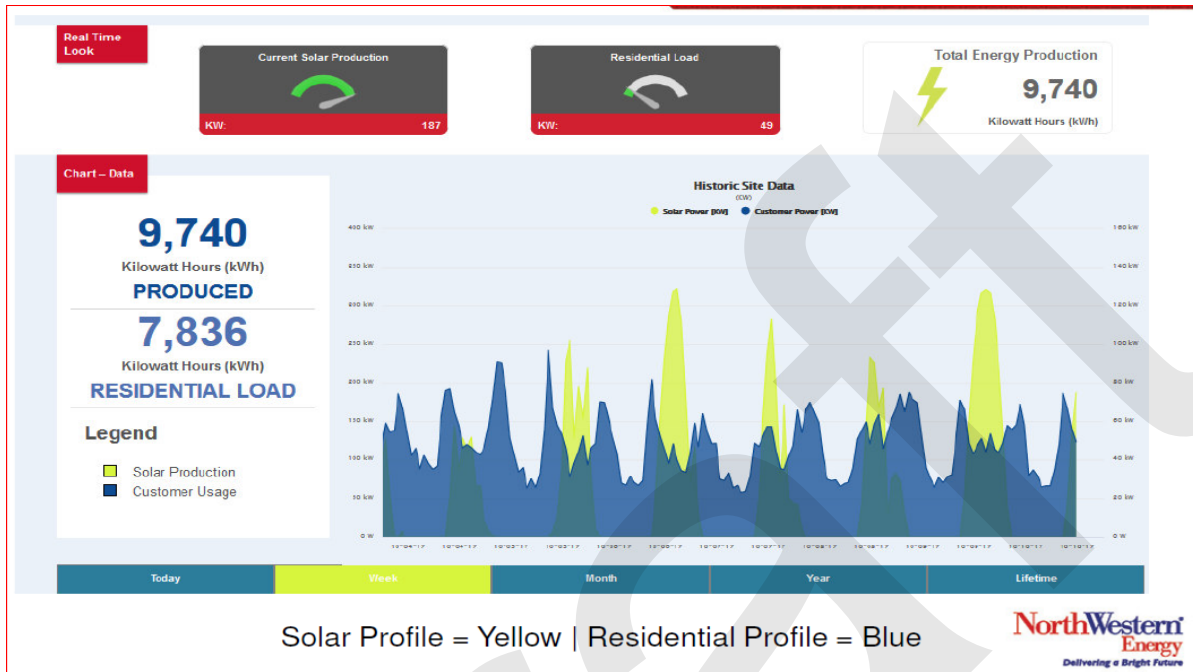


Figure 8-5. Bozeman Solar Microgrid Container Boxes and Controllers



Figure 8-6. Bozeman Solar Microgrid 380 kilowatt Array



Missoula Solar Projects

NorthWestern Energy, Missoula County Public Schools and the City of Missoula are developing collaborative solar projects designed to learn more about the performance of solar energy on our distribution system in the Missoula area. Construction of the projects will begin in the spring of 2019 and include installation of solar technology at Hellgate, Sentinel, Big Sky and Willard high schools. Different locations will integrate different solar PV technology and the Big Sky installation will include energy storage. Sentinel and Hellgate High School will utilize a vertical array of solar PV panels that will produce energy that aligns with each school's consumption pattern, as well as help with snow shedding during winter months.

Figure 8-7 is an example of the proposed design at Sentinel High School and Figure 8-8 and Figure 8-9 are examples of the proposed design at Hellgate High School.

Figure 8-7. Sentinel High Solar PV Project Vertical Array Sketch



Figure 8-8. Hellgate High Solar PV Project Vertical Options Sketch

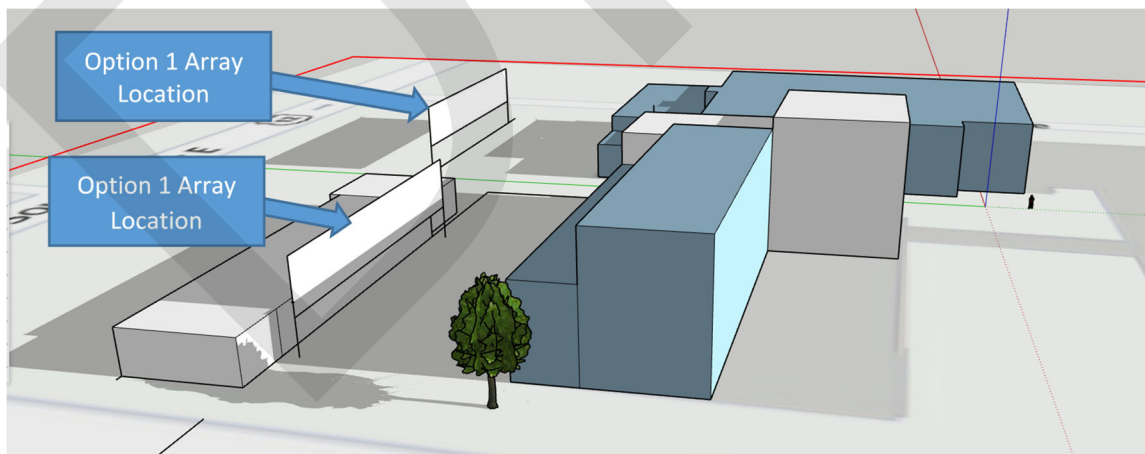
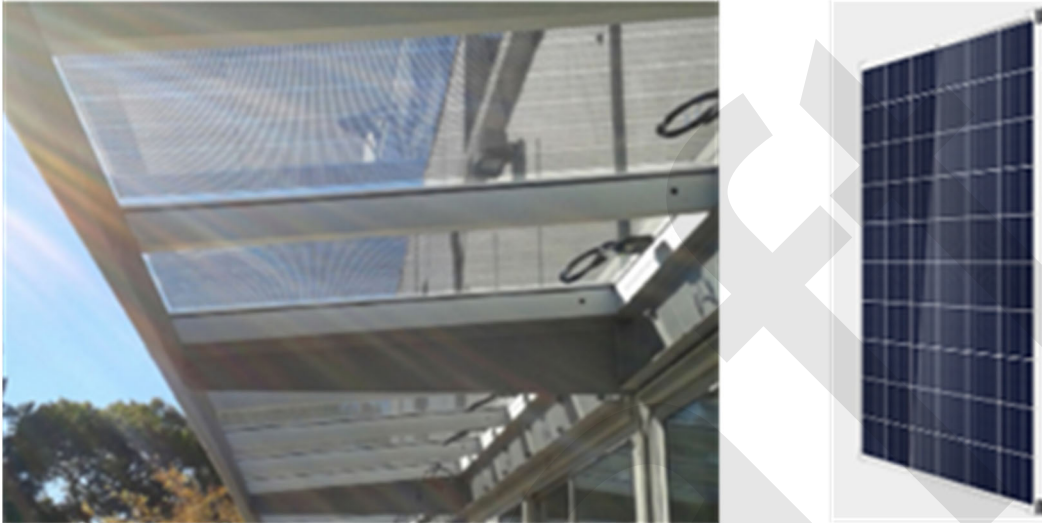


Figure 8-9. Hellgate High See-Through/Bifacial and Opaque Solar PV Options



Willard High School will use either a solar fence or a bike canopy concept to demonstrate new solar PV technology. Figure 8-10 and Figure 8-11 are examples of these types of solar installations.

Figure 8-10. Fence/Noise Barrier Solar PV Options



Figure 8-11. Bike Canopy Solar PV Options



Big Sky High School’s proposed installation will use a solar walkway to provide shading along with an energy storage element to demonstrate new solar PV technology. Energy storage will be charged from the onsite solar production and provide power to loads located in the gym for community events. Figure 8-12 is an example of the proposed design at Big Sky High School.

Figure 8-12. Big Sky High Solar PV Project Walkway Canopy Example

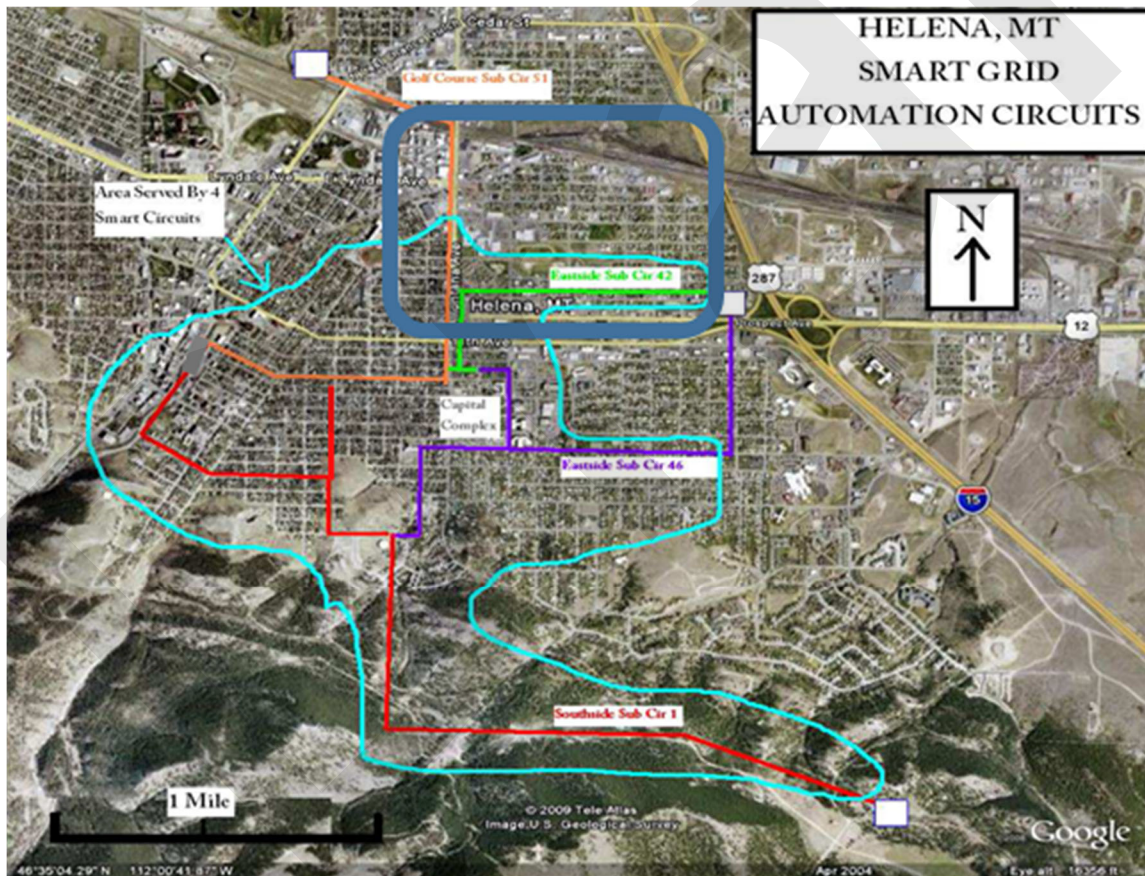


Residential Solar Scape – Palm Springs, CA

Helena Solar Project

The Helena Solar Project is slated to begin design in fall 2019 and will be installed in Helena’s 6th Ward Area. This project will be a test of utility owned rooftop solar PV and utilize the existing distribution and communication system of the NorthWestern Smart Grid Pilot Project. Figure 8-13 shows the preliminary location of the project.

Figure 8-13. Helena Solar PV Project Area



Super-Capacitor Energy Storage

In November of 2018, NorthWestern announced an investment of \$2.5 million in Kilowatt Labs, Inc. (KLI), a New York-headquartered designer and manufacturer of innovative super-capacitor energy storage and power management solutions. KLI super-capacitor technology aligns closely with our thinking about the evolution of the infrastructure that serves our customers, from rural to industrial, and at multiple layers of our network. NorthWestern will be working with KLI to develop potential solutions throughout our network.

Small Modular Nuclear Reactors (SMRs)

SMRs are a promising technology capable of providing reliable, non-variable, clean, and carbon-free power. SMRs have an output of 300 MWs or less and are comprised of factory-fabricated components transported to a nuclear power plant location for on-site assembly. Some SMR designs allow for output to be varied over days, hours, or minutes, enabling the SMR to be used for flexible capacity and grid balancing.

In 2018, the US Department of Energy's (DOE) Office of Nuclear Energy announced an agreement with Utah Associated Municipal Power Systems and Battelle Energy Alliance (DOE contractor operating the Idaho National Laboratory (INL)) to construct twelve, 50 MW capacity SMRs at the INL site near Idaho Falls, Idaho with a commercial operation date sometime in 2026. NorthWestern will be involved in this project because we own and operate an affected transmission system.

CHAPTER 9

ENVIRONMENTAL

Environmental Issues that Influence the 2019 Plan

Introductory Statement

NorthWestern Energy provides affordable, reliable, and safe energy services while responsibly managing the natural resources under our stewardship. We support using renewable resources when consistent with the needs of the portfolio and our commitment to ensure our customers always get the energy they need in all weather conditions. Our commitment to environmental stewardship and compliance affects all facets of our business, including our resource procurement planning.

All forms of electric generation involve environmental impacts and mitigation requirements and NorthWestern Energy employs a team of experts to ensure our projects are operated in compliance with environmental regulations and operating license requirements. We prepare an annual publication called “Environmental Stewardship: Our Commitment in Action” which is available on our website.¹ We encourage those interested to review this publication.

River Management Partnerships

Partnering with agencies and private parties, NorthWestern employs an innovative approach to complying with our hydroelectric project FERC license requirements. Under

¹http://www.northwesternenergy.com/docs/default-source/documents/environment/nwe_enviroreport_2017_web.pdf

a Memorandum of Understanding (MOU), NorthWestern, the US Fish & Wildlife Service, Montana Department of fish, Wildlife and Parks, US Forest Service, US Bureau of Reclamation, and the US Bureau of Land Management work collaboratively to implement studies and projects to protect, mitigate and enhance fish, wildlife, habitat and water quality and improve public recreation. Habitat improvement on rivers and tributaries is a high priority as is our program to protect and enhance endangered species and species of special concern. NorthWestern has funded and partnered with agencies to expand populations of genetically pure native westslope cutthroat trout, recover pallid sturgeon and establish new breeding pairs of trumpeter swans (following photo).



NorthWestern Energy has provided funding each of the last 10 years to support the installation and operation of a system of 12 remote fish-tracking stations located on a 225-mile stretch of the Missouri River from Great Falls to Fort Peck Reservoir.

In recent years, we have assisted in population surveys and funded research on softshell turtles (pictured below), a Montana species of special concern. Our employees worked with representatives from the Montana Department of Fish Wildlife and Parks and Montana

State University during the summer of 2017 to obtain turtle-population density information in a 10-mile stretch of the Missouri River. We will use this information as the baseline for long-term monitoring of population stability of this sensitive species.



Avian Protection Program



Researchers conduct a post-construction inspection of a wind generation facility in order to assess the effects of bird and bat collisions.

NorthWestern Energy has a long standing commitment to deter birds from colliding with wind farm turbines and power lines, and nesting on energized structures. To reduce the risk of power outages and osprey mortality, we install deterrents on energized structures to prevent osprey from starting new nests and often install nesting platforms nearby. This provides both a safe nesting location for osprey, which return to the same nest every year, and more reliable service for our customers. Currently on our Montana electric system, we have more than 150 osprey platforms, providing a safe home for these amazing birds. In addition, we actively communicate the threat baling twine presents to osprey when they use discarded twine in their nests.



A NorthWestern Energy Lineman assists a university biologist in studying active osprey nests.

NorthWestern’s raptor biologist was awarded the Montana Chapter of the Wildlife Society’s Distinguished Service Award in 2017 for “tireless commitment to the protection, conservation and enjoyment of Montana’s wildlife.” In NorthWestern Energy’s pursuit of additional sources of renewable energy in the state, our raptor biologist ensures projects conduct the necessary studies in order to minimize impacts to migratory birds and wildlife in general. In 2012, when NorthWestern purchased the Spion Kop wind project near Great

Falls, we did not follow the wind industry standard of hiring 3rd party consultants to do post-construction monitoring – we surpassed it. NorthWestern implemented an innovative approach by proposing the Montana Fish, Wildlife and Parks (MFWP) design and implement wildlife monitoring with guidance from a Technical Advisory Committee (TAC) (which includes representatives of MFWP, the USFWS, Montana Audubon, the University of Montana, and NorthWestern). This approach ensured monitoring was completely transparent, produced public data available to state and federal wildlife managers and also gave the MFWP direct experience to better prepare for consultations with developers. Spion Kop is only the second wind farm in Montana to use a TAC, the only wind farm in Montana to make all data publicly available, and the first (and perhaps still the only) wind farm in the nation to employ a state wildlife agency in wildlife monitoring.

NorthWestern Energy's Balanced Energy Mix

We are committed to providing a diverse, balanced, cost-effective and reliable portfolio of resources that isn't overly dependent on a single technology. As previously mentioned in Chapter 4, about 69% of the nameplate capacity of our supply portfolio is from owned and contracted clean hydro, wind and solar resources.

Renewable Energy Resources

NorthWestern Energy has invested approximately \$2.2 billion in renewable resources and cost-effective demand side management. This includes the hydro acquisition, which provides our customers long-term price stability for a significant portion of the portfolio that serves them, from a clean, renewable and carbon-free resource. Unlike other renewables, hydroelectric generation provides carbon-free energy and capacity as well as

additional, or ancillary, services required for a reliable system (spinning and non-spinning reserves as well as on-demand generation increases or decreases).

As indicated in Chapter 4 we have numerous contracts with small renewable projects using hydro, wind and solar generation. Since late 2016, we have added about 159 MWs of long-term energy supply contracts with third-party wind and solar developers, and this figure will grow to 398 MWs by the end of 2019 (see Figure 4-1 in Chapter 4). As stated in Chapter 4, NorthWestern currently has requests from an additional 2,545 MWs of QF projects for avoided cost calculations or draft PPAs. Several more MWs of renewable generation will be added in the next two years which will increase the percentage of variable generation in our portfolio and increase the need for reliable, flexible capacity resources so we can continually balance supply and demand and prevent service disruptions. Of these requests, 104.8 MWs fall under the 3 MW standard offer limit for the QF-1 Tariff. The larger projects, up to 80 MWs in size, include 1,417 MWs of solar, 888 MWs of wind, and 134.7 MWs of other technologies or combination projects.

For more than 17 years, NorthWestern Energy has helped fund installation of photovoltaic solar and wind systems through our USB program. In Bozeman, Montana we partnered with the City of Bozeman, Montana State University and Schweitzer Engineering Laboratories to build a 385 kw solar project that we are using to pilot community solar models, test the applications of advanced inverters and determine the value to the grid.

Greenhouse Gas Emissions

In 1990, NorthWestern's predecessor company in Montana, the Montana Power Company, began a voluntary greenhouse gas reduction plan to reduce carbon dioxide emissions by using demand side management programs, improving hydroelectric generation at existing

hydro plants, promoting renewable energy, reducing electrical losses from generation and transmission, and implementing a forest carbon management plan.

NorthWestern's ownership of coal-fired generation is less than 10% of the total in the state of Montana. The contracted waste coal and petroleum coke resources are QFs, which we are required by law to use, and account for about 11% of the energy provided by our portfolio yet contribute an annual average of about 37% of the CO₂ emissions associated with our portfolio. Carbon dioxide emissions are also associated with energy we need to purchase from the market.

As previously stated in this Plan our portfolio requires the addition of a considerable amount of capacity. Resources chosen to fill the large capacity deficit must be able to provide a reliable source of flexible generation and be controlled by NorthWestern using AGC. NorthWestern cannot simply choose resources based solely on levels of greenhouse gas emissions. The capacity resources will be chosen using a competitive, all source, technology agnostic, RFP process in order to identify the most cost-effective resources.

Regulation of Greenhouse Gas (GHG) Emissions

For context we feel it's important to understand the history of efforts to regulate GHG emissions. The following sections discuss this history.

Clean Power Plan

The Environmental Protection Agency (EPA) published a proposal to regulate CO₂ emissions from existing power plants on June 2nd, 2014. NorthWestern Energy actively

engaged with EPA, state agencies, state governments, utility regulatory commissions, utilities, business groups, the Edison Electric Institute, the Coalition for Innovative Climate Solutions and others, analyzing the proposed rule in order to identify opportunities and also areas where more work and analysis were required before states could draft implementable compliance plans and ensure. Concerned our customers were being punished rather than rewarded for their low carbon energy use, NorthWestern submitted constructive comments to EPA. The comments focused on some of the significant practical problems and challenges associated with the proposed rule, along with recommendations/requests for EPA to consider for the final rule to help EPA ensure the final rule addressed the economical, technical and physical realities as well as the environmental factors associated with delivering electricity safely, reliably and securely.

The final Clean Power Plan (CPP) was published in the Federal Register on October 23rd, 2015. Citing a range of legal and technical concerns, several states, utilities and trade groups filed petitions for review in the US Court of Appeals for the District of Columbia (DC Circuit). By December of 2015, a bipartisan majority of the US Congress formally disapproved of the CPP pursuant to the Congressional Review Act. On February 9th, 2016, the US Supreme Court issued a stay pending resolution of the case by the DC Circuit. On March 28th, 2017, President Trump signed the Energy Independence Executive Order (Executive Order) which, among other things, directed EPA to review and, if appropriate, suspend, revise or rescind the CPP. Due in part to this development, EPA requested the DC Circuit hold the court case in abeyance and the DC Circuit has incrementally granted EPA's requests.

Affordable Clean Energy Rule

On October 16th, 2017 a notice of EPA's proposal to repeal the CPP was published in the Federal Register (FR). EPA proposed to repeal the CPP because it was premised on a novel

and expansive view of EPA’s authority which was inconsistent with the Clean Air Act (CAA). In a separate but related action, in December 2017, EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) to solicit information from the public regarding a potential future rulemaking to limit greenhouse gas emissions from existing electric generating units. On August 21st, 2018, EPA proposed the Affordable Clean Energy (ACE) rule which would establish emission guidelines to be used by States to develop plans to address GHG emissions from existing coal-fired EGUs. If finalized, the ACE rule will replace the 2015 CPP. Comments on the ACE rule were due October 31st, 2018.

NorthWestern concurs with EPA’s proposal to replace the CPP “with a rule that corrects the fundamental legal flaws in the CPP to more appropriately balance federal and state responsibilities under CAA section 111(d).”² We agree with EPA’s determination that the best system of emissions reduction (BSER) established in the CPP exceeded its authority and that BSER is determined by “evaluating technologies or systems of emission reduction that are applicable to, at, and on, the premises of the facility for an affected source.” We also agree with EPA’s proposal to determine that heat rate improvements (HRIs) are the BSER for existing, fossil-fuel fired, steam generating units. EPA’s proposed ACE rule includes a requirement that “The standard of performance must be an emission performance rate relating mass of CO₂ emitted per unit of energy (e.g. pounds of CO₂ per MWh).”³ We believe EPA must allow states the flexibility to consider a wide range of other performance standards such as mass of CO₂ emitted per unit of time or separate emission rates for different load ranges. NorthWestern will evaluate the ACE rule after it is published in final form in order to determine if there are any effects on resource selection.

² 83 Federal Register at 44748.

³ Proposed 40 CFR §60.5755a(a)(1)

Carbon Cost Forecasting

Prior Resource Plans

The 2013 Plan considered carbon costs in the context of the information provided in the 2013 U.S. Energy Information Administration (EIA) Annual Energy Outlook and in advance of the EPA 111(d) proposed rules for existing CO₂ emitting sources. NorthWestern incorporated the carbon penalty forecast into our planning work as a proxy for the eventual form of greenhouse gas regulation implemented. In selecting the EIA GHG15 carbon case as the base carbon assumption, NorthWestern derived a base carbon pricing assumption of \$21.11/ton starting in 2021 and escalating annually at 5% over the 20-year planning horizon and through 2043. For stochastic modeling purposes, the carbon price was varied above and below the annual base value according to a triangular distribution in recognition of the high degree of uncertainty associated with the carbon price variable and how it might actually materialize over time. One hundred iterations of the model were executed to create a distribution of total portfolio cost where carbon cost, like other stochastic variables such as electricity and natural gas price, varied above and below the starting value defined by the forecast schedule. Values never went below zero. In its comments on the 2013 Plan, the PSC directed NorthWestern to make changes to our evaluation of future carbon costs. Specifically, the PSC requested the following: a more rigorous evaluation of potential CO₂ costs, evaluation of alternative CO₂ price trajectories, alternative ways of defining the CO₂ price distribution, and specific guidance on CO₂ from ETAC.

For the 2015 Plan, based on the PSC comments, NorthWestern did the following: (1) solicited input from ETAC about carbon costs and the use of a triangular distribution in stochastic simulations; (2) identified and considered additional sources of price forecasts for CO₂ and shared them with ETAC; (3) employed a base case carbon pricing assumption

and two alternatives including a zero carbon cost case and a high carbon cost case in the 2015 Plan; and (4) completed portfolio simulations for the base capacity plan using all three carbon pricing trajectories.

Prior resource planning cycles recognized the EIA Annual Energy Outlook as a guiding source of carbon cost planning information. However, the 2015 EIA Annual Energy Outlook excluded projections of carbon prices. This left NorthWestern, and our advisory group to identify and select carbon cost estimates without the use of information from EIA. The following sources were reviewed to inform NorthWestern’s 2015 Plan: CO₂ Price Report January 2016 (Synapse Energy Economics), PacifiCorp 2015 Integrated Resource Plan, Xcel Energy 2015 IRP (preferred portfolio), Puget Sound Energy 2015 IRP (low, mid, and high case), Portland General Electric 2015 Update.

MPSC Orders and Decisions Affecting Consideration of Carbon Costs

MPSC Order on Reconsideration 7500d QF-1

In Docket D2016.5.39 (QF-1 docket), the MPSC decided to exclude costs attributable to the potential for future regulation of carbon dioxide emissions from the calculation of avoided costs, reasoning that unknown future costs of carbon dioxide emissions in an avoided cost calculation exposed customers to unnecessary risk. The MPSC did not see a sufficiently accurate way to forecast a carbon price and noted the following in its determination: (1) unique uncertainty surrounding future emissions pricing; (2) changes in nationwide political landscape and regulatory environment; and (3) resource planning rules that continue to require NorthWestern to estimate future emissions costs when evaluating supply- and demand-side resources available to meet our retail supply needs.

The MPSC also observed that for carbon dioxide, in contrast to other inputs to the standard rate avoided cost calculations underlying QF-1 tariff rates, such as future natural gas prices,

no regional market price history exists, no regional forward market price information exists, no region-wide emissions regulations exist, and there are no market fundamentals to guide the process of estimating emissions prices over the long term. After years of hypothetical forecasting of this variable and anticipating a national market place to form, they said, an independently variable measure of this cost has not emerged.

MPSC Order on Reconsideration 7535b MTSUN

In Docket D2016.12.103 (MTSUN docket), the MPSC rejected the use of a carbon adder to supplement energy prices, using the same logic as in D2016.5.29 (QF-1 docket).

2019 Plan Carbon Cost

To align with PSC direction in D2016.5.39 (QF-1) and D2016.12.103 (MTSUN), NorthWestern is not including a carbon cost in the base case for the 2019 Plan. Instead, carbon is considered in a separate scenario. For the carbon scenario, NorthWestern relies on the NEM Study conducted by Navigant Consulting. The following sections describe the methodology and background behind Navigant's CO₂ price forecast.

Navigant's CO₂ Price Forecast

Methodology

Navigant produced its CO₂ price forecast using the proprietary Portfolio Optimization Model (POM) to simulate economic investment decisions and power plant dispatch. The model simultaneously performs least-cost optimization of the electric power system expansion and dispatch over multiple decades. POM can optimize based on a cost-minimization objective or on other considerations such as sustainability, technological innovation, or impacts on other sectors, such as natural gas. POM was used to determine the CO₂ prices that would result from a likely CO₂ emission reduction policy.

Assumptions

The two major assumptions used in Navigant’s modeling were natural gas prices and capacity additions and retirements in the NWPP sub-region of WECC, in which the majority of Montana is located. Natural gas prices at the major gas hubs in NWPP were forecasted to be approximately \$3.00 per MMBtu in 2017 and increase to between \$5.00 and \$6.00 per MMBtu by 2040. Resource additions in the region were assumed to consist of some near and mid-term natural gas combined-cycle capacity, substantial renewable resource additions, and generic simple-cycle capacity needed to maintain generation reserves. There were significant coal retirements assumed, driven primarily by the EPA’s regional haze determinations, which would lead to significant reduction in CO₂ emissions.

CO₂ Policy

Navigant assumed a cap-and-trade policy that targets 28% reductions of CO₂ emissions from the power generation sector from 2005 levels in 2028, ramping up 1% each year to 50% in 2050. This cap-and-trade program would apply to the entire WECC region, except for California, whose current program targets getting to 1990 emission levels overall by 2020 and 80% below 1990 levels by 2050.

Results

Table 9-1 shows forecasted annual CO₂ prices through 2050; prices are shown in real 2016 dollars per short ton and nominal dollars per short ton. Nominal prices were determined using a 2% annual inflation rate based on a 20-year average inflation escalation for Gross Domestic Product, provided by the U.S. Bureau of Economic Analysis.

Table 9-1. Forecasts of CO₂ Prices

Year	CO2 Prices		High CO2 Prices	
	2016 Dollars (\$/ton)	Nominal (\$/ton)	2016 Dollars (\$/ton)	Nominal (\$/ton)
2019	-	-	-	-
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	\$16.74	\$20.00
2026	-	-	\$17.09	\$20.83
2027	-	-	\$17.44	\$21.69
2028	\$4.50	\$5.71	\$17.81	\$22.59
2029	\$5.50	\$7.11	\$18.19	\$23.53
2030	\$7.50	\$9.90	\$18.58	\$24.51
2031	\$8.50	\$11.44	\$18.97	\$25.53
2032	\$9.50	\$13.04	\$19.37	\$26.59
2033	\$10.50	\$14.70	\$19.78	\$27.69
2034	\$11.50	\$16.42	\$20.19	\$28.84
2035	\$12.00	\$17.48	\$20.61	\$30.03
2036	\$12.50	\$18.57	\$21.05	\$31.28
2037	\$14.00	\$21.22	\$21.50	\$32.58
2038	\$14.50	\$22.42	\$21.95	\$33.93
2039	\$15.00	\$23.65	\$22.41	\$35.34
2040	\$15.50	\$24.93	\$22.89	\$36.81
2041	\$17.15	\$28.14	\$23.36	\$38.33
2042	\$18.05	\$30.21	\$23.86	\$39.92
2043	\$18.95	\$32.34	\$24.36	\$41.58
2044	\$19.85	\$34.55	\$24.88	\$43.31
2045	\$20.74	\$36.84	\$25.40	\$45.10
2046	\$21.64	\$39.20	\$25.93	\$46.97
2047	\$22.54	\$41.65	\$26.48	\$48.92
2048	\$23.44	\$44.17	\$27.04	\$50.95
2049	\$24.34	\$46.78	\$27.61	\$53.07
2050	\$25.23	\$49.84	\$28.19	\$55.27

High CO₂ Prices

Table 9-1 includes a second set of CO₂ costs labeled High CO₂ Prices. These CO₂ prices are derived from NorthWestern's 2015 resource plan, but the implementation of those costs has been delayed three years from that contained in the 2015 Plan. The higher CO₂ costs start sooner than the Navigant derived costs, are higher, and are consistent with a prior MPSC order.

New Sources - Performance Standards for Carbon Emissions

In 2015, EPA finalized standards to limit carbon dioxide emissions from new, modified and reconstructed power plants. The Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units regulation. EPA used its authority under Section 111(b) of the Clean Air Act to set standards to limit CO₂ emissions for two types of fossil-fuel fired sources:

- Stationary Combustion Turbines (natural gas and oil fired, with provisions for other fuels)
- Steam Electric Generating Units (coal-fired, with provisions for other solid fuels)

EPA selected specific technologies representing the BSER for the two regulated source types above. Specifically related to this Plan is EPA's BSER for new Stationary CTs which is based on emissions of CO₂ achievable from a natural gas combined-cycle (NGCC) plant. The CO₂ emission standard is 1,000 lbs of CO₂ per gross MWh produced. There are exceptions if the CT serves a generator less than 25 MWs or the hours of operation are limited. In scenarios where CTs are included in the modeling inputs, hours of operation are restricted in order to comply with this regulation.

On April 4, 2017, pursuant to the aforementioned Executive Order, EPA announced it was reviewing and, if appropriate, would initiate proceedings to suspend, revise or rescind this regulation. On December 6, 2018 EPA proposed revisions to this regulation and is accepting comments through February 19, 2019. EPA is not proposing any changes to the performance standards for newly constructed or reconstructed stationary CTs, however they are taking comment regarding the increased use of simple cycle aeroderivative CTs, including as back-up generation for wind and solar resources, whose operation may exceed the non-base load threshold described in the 2015 rule. NorthWestern will monitor the status of EPA's proposed revisions and determine if any changes are necessary to the assumptions used for the modeled scenarios in this plan.

Summary of Key Colstrip Environmental Risks

Regional Haze Rule

The EPA's regional haze rule (RHR) finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, the EPA issued final amendments to its Regional Haze Rule. These amendments require emission controls known as the Best Available Retrofit Technology (BART) for emissions of certain pollutants that have the potential to impact visibility. These pollutants include fine particulate matter (PM), nitrogen oxides, sulfur dioxide, certain volatile organic compounds, and ammonia. States were given until December 2007 to develop state implementation plans (SIPs) to comply with the Regional Haze Rule. Montana did not develop a plan to comply, and EPA subsequently developed a Federal Implementation Plan (FIP) for Montana in September of 2012 to cover the first planning

period (2008 – 2018). The FIP included requirements for upgrades to Colstrip Units 1 & 2 but did not include immediate requirements for Units 3 & 4.

States are expected to submit SIPs for the second planning period (2018-2028) no later than July 2021. If a state fails to submit a SIP by that time, EPA would again be responsible for publishing a FIP to ensure progress toward natural visibility conditions. At this time, the state of Montana plans to take the lead on all aspects of the RHR. Montana is planning on replacing the existing FIP with a SIP by incorporating the BART requirements into Montana state regulation. Montana is working toward submitting a SIP for the second planning period on an accelerated timeline by early 2020, if possible. It is likely that Colstrip Units 3 and 4 will undergo analysis to determine whether additional controls will be required. NorthWestern cannot predict how the results of this analysis may, or may not, affect Colstrip Units 3 and 4. For purposes of the Plan, we assume Colstrip Units 3 and 4 will not require additional material upgrades to comply with the RHR during the 20-year planning period of the Plan. Obviously, should Montana conclude Units 3 and 4 require material upgrades a detailed analysis would be required at that time.

Mercury and Air Toxics

The Mercury and Air Toxics Rule (MATS) became effective April 16, 2012. The MATS rule requires new and existing coal-fueled facilities achieve emissions standards for mercury, acid gases, and other hazardous pollutants. Measurements of filterable PM are used as a surrogate to determine compliance with the emissions standards for non-mercury metals. Existing sources were required to comply with the new standards by April 16, 2015. As allowed by the rule, the Colstrip facility requested a one-year extension to allow time for all units at Colstrip (1 through 4) to become compliant as a facility.

The Colstrip facility was in compliance with all MATS requirements from April of 2016 until June of 2018. In June of 2018, measurements of particulate matter were above allowable limits for Units 3 and 4; all other MATS requirements were in compliance. After extensive investigation, corrective actions were implemented and the units were tested and back in full operation in September of 2018. No additional actions or upgrades are anticipated at this time. Therefore, for this Plan we assume there will be no additional material upgrades required for compliance with the MATS rule.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs) including coal ash, are byproducts from the combustion of coal in power plants. The EPA issued a final rule in April of 2015 to regulate CCRs as a nonhazardous waste under Subtitle D of Resource Conservation and Recovery Act and establish minimum nationwide standards for the disposal of coal combustion residuals.

The Colstrip facility is complying with the CCR rule and the operator is implementing required actions. See the discussion below regarding wastewater.

National Ambient Air Quality Standards (NAAQS)

The Clean Air Act sets allowable ambient air quality standards for six “criteria” pollutants. The rule requires periodic review of the science used to establish the standards and the standards themselves. With each review, the standards are compared to ambient air quality in each state or part of each state to determine if the state or part of each state is in “attainment” or “non-attainment.” If a state contains any areas of “non-attainment”, the state must propose a plan and schedule to reduce emissions to achieve attainment.

Currently, the Colstrip area of Montana is in attainment for all criteria pollutants. Further reductions in emissions resulting from compliance with MATs are expected to keep the Colstrip area in attainment with future NAAQS reviews/revisions. NorthWestern does not expect additional material cost impacts related to NAAQS compliance. Therefore, we did not include any additional costs related to NAAQS compliance in our modeling scenarios.

Wastewater

In August 2012, Talen Energy (Talen) (the Colstrip Plant Operator) and the Montana Department of Environmental Quality (MDEQ) signed an Administrative Order on Consent Regarding Impacts from Wastewater Facilities (AOC). The AOC sets up a comprehensive program for investigation, interim response, remediation and closure of the holding ponds and covers the same facilities required to comply with the CCR rule. Talen is implementing AOC requirements as they are approved by MDEQ. NorthWestern's share of the capital and financial assurance costs associated with the AOC were incorporated in the cost structure for Colstrip in this Plan.

CHAPTER 10

PORTFOLIO MODELING

NorthWestern's Portfolio Additions

Overview

NorthWestern uses a modeling and simulation software to analyze the performance of different energy supply portfolios under a wide range of possible future conditions. PowerSimm™ models the variability of key factors like weather, electric load, renewable generation, and gas and electricity market prices and their associated impacts on power costs and the optimal dispatch of the resources in NorthWestern's energy supply portfolio. These analyses are performed at an hourly time-step, which provides insight into the unique operating characteristics of renewable resources and the flexibility of dispatchable resources to respond optimally, and rapidly, to changing market conditions. Portfolio model runs are summarized, producing levelized, risk-adjusted net present value of revenue requirements and estimated carbon dioxide emissions by resource in pounds of CO₂ per MWh.

Portfolio Modeling Platform

NorthWestern uses the PowerSimm™ modeling platform developed by Ascend Analytics to assess various resource portfolios. The PowerSimm platform consists of multiple modules. The Automatic Resource Selection (ARS) module identifies resources that perform best across a wide range of modeled conditions and could be used to best serve our customers' future resource needs. The list of resources considered for ARS is limited because costs and operating characteristics of modeled resources must be known and

measurable. NorthWestern cannot predict all resources or combinations of resources that may be proposed during a competitive solicitation process, or which may be offered for opportunity purchase. Therefore, modeling is limited to resources with known and measurable operating characteristics in order to provide insight about resources that could potentially serve customers in the future.

Resource planning involves a trade-off between long-term capital investment decisions and variable operating costs; the ‘best’ resource (or combination of resources, if multiple resources perform better than one) is typically one that minimizes the net present value of the revenue requirement, including the recovery of capital expenditures and fixed and variable costs. ARS uses overnight capital costs¹, expected revenues, and both fixed and variable operation and maintenance costs (O&M) to calculate a levelized annual revenue requirement for each portfolio modeled. The analysis also accounts for the residual value of capital investments that are not fully amortized over the planning horizon. These calculations are dependent on general economic assumptions including inflation rates, relevant tax rates, NorthWestern’s weighted average cost of capital (WACC), and the depreciation life of the resource.

ARS analysis seeks a solution that minimizes the net present value of capital expenditures and production costs, subject to constraints. The model must be constrained so that it produces realistic results. Constraints include limits on market sales and purchases of energy and capacity, and reserve margin requirements. Constraints can be defined to vary over the planning horizon to reflect changing market conditions or other factors such as the

¹ Overnight cost is the cost of a construction project if no interest was incurred during construction, as if the project was completed "overnight."

requirements to participate in an organized market. For this Plan, the ARS analysis included the following constraints.

- Resource additions were limited to about 200 MW per year.² This constraint prevents ARS from achieving NorthWestern’s reserve margin in the first year while still achieving a 16% reserve margin by 2025.
- Resources are not placed in service prior to 2022. This restriction allows time to file the 2019 Plan, conduct a competitive solicitation and negotiate contracts, and allows time for construction should new-build resources win a competitive solicitation.
- Market sales were constrained to no more than 10% over annual customer load. This restriction prevents the model from overbuilding resources for the express purpose of selling energy into the market.

PowerSimm Hourly Model

PowerSimm explicitly models the impacts that variations of load, market prices, weather conditions and renewable generation have on the performance of different resource portfolio scenarios. PowerSimm’s model is stochastic³, which means that each key variable in the model (e.g., market prices, weather, load, renewable generation, etc.) varies

² As explained in Chapter 5, NorthWestern will be joining the EIM in 2021 and assumes entry into an RTO by 2025. The 200 MW/year limitation allows NorthWestern to reach a 16% reserve margin by 2025. This constraint will be subject to ongoing review.

³ Stochastic simulation methods capture key short- and long-term uncertainties that are fundamental to estimating fuel prices, market electricity prices, generating plant outages, production from renewable energy resources, and hydrological conditions. Stochastic analysis enables the model to explicitly capture the impact that uncertainty in key variables can have on the expected value (and likely range of values) for each portfolio.

according to the underlying statistical distributions of each variable and the expected correlations⁴ between variables.

The PowerSimm model begins by generating weather simulations. Weather is modeled as the key driver of electric load, wind, solar and hydro generation, and spot gas prices. Spot prices for electricity are then determined as a function of these variables. Based on the simulations of these variables, PowerSimm then determines the economically-optimal hourly generation from NorthWestern’s dispatchable resource fleet to find a cost-optimized dispatch schedule for each resource portfolio scenario. The use of stochastic analysis allows NorthWestern to examine how a portfolio may perform under a wide range of potential conditions. Each portfolio scenario undergoes 100 simulations, each one representing 20 years of hourly analysis and each representing a unique combination of weather, prices, loads, and renewable resource production.

Simulation Inputs

The following key types of historical data are used to model future conditions and the performance of different energy supply portfolios:

- Historical weather data (daily minimum and maximum dry bulb temperatures),
- Historical load data (both NorthWestern’s load and WECC-wide load),
- Historical generation data from NorthWestern’s wind, hydro, and solar resources,
- Historical power prices at the Mid-Columbia trading hub (Mid-C), and
- Historical natural gas prices at the Alberta Energy Company (AECO) trading hub.

⁴ Correlation means the mutual relationship or connection between two or more things; the interdependence of two or more variables. The expected correlations between PowerSimm variables are determined through an analysis of historical relationships and observed trends.

In addition to the data sources named above, PowerSimm includes the following projections:

- **Forward price curves for electricity.** The price curves are based on: a 15 calendar day average of monthly Intercontinental Exchange (ICE) forward prices for Peak and Off-Peak periods at Mid-C through 2021 until the markets are illiquid; heat rate projections based on a fundamental modeling approach that takes into account structural changes associated with the increasing penetration of variable renewable resources in the WECC⁵; and, assumptions that long-term equilibrium prices will be effectively bounded by the marginal cost of a new capacity resource⁶.
- **Forward price curves for natural gas.** These are based on a 15 calendar day average of monthly Natural Gas Exchange (NGX) forward prices for the AECO hub through 2021, after which prices are escalated using the EIA's 2018 annual escalation rates for natural gas at Henry Hub.
- **Hourly price shapes.** These are projected forward using an analysis of the fundamentals of the WECC generation mix and the expected trend of increasing penetration of variable renewable resources and announced retirements of thermal resources.
- **Spot price volatility.** This is projected forward based on the observed relationship between levels of variable renewable resources and observed price volatility. Spot price volatility is expected to continue increasing as more renewable resources come online, but is assumed to slow after 2030.

⁵ See *Ascend Analytics – WECC Market Outlook and Modeling* included in Volume 2 of this plan.

⁶ For more analysis on future market prices and the effects of increasing variable renewable generation, see Berkley Lab's *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making*, <https://emp.lbl.gov/publications/impacts-high-variable-renewable>

Evaluating Risk Premium

By simulating the performance of a resource portfolio under a wide range of possible future conditions, different portfolios can be compared based on “expected” (i.e., average) cost across all future conditions considered, as well as the uncertainty of possible costs. The uncertainty reflected in the estimated economic values and costs for different portfolios can be compared by estimating the likelihood that future conditions may result in a portfolio being extremely costly. This is measured by a portfolio’s “risk premium,” which is the probability weighted average of the estimated costs for each portfolio above the expected (mean) value. The risk premium is the difference between the 95th percentile and the mean of estimated costs for a portfolio and is a measure of the likely magnitude of costs above the expected value. The risk premium for each portfolio is added to the portfolio’s estimated cost, effectively “penalizing” riskier portfolios relative to less risky ones. Combining cost and risk into one value allows for a simple comparison of costs and risks associated with portfolio scenarios.

Loss of Load Probability

A foundational goal of resource planning is to ensure that there is a sufficient amount of energy and capacity to serve the load at all times. Reliability can be examined by determining the expected Loss of Load Probability (LOLP) for each portfolio. Ascend calculates the annual LOLP for each portfolio scenario over the entire planning horizon based on stochastic simulation of weather, load, renewable and thermal generation, and unplanned outages for thermal resources. Simulation results are compared to generation capacity and firm power contracts available in each hour. A loss of load occurs during the hours in which load requirements exceed available capacity (known as “loss of load hours” or LOLH). LOLHs are calculated based only on the generation assets and firm contracts in a portfolio. This calculation does not include day-ahead or real-time market purchases. LOLP is calculated as the percentage of hours in which a loss of load occurs. The resulting

estimated LOLPs for each portfolio and each year can then be used to determine how much additional capacity might be needed to meet reliability targets. NERC uses a standard of no more than one day in ten years for the probability of a loss-of-load (equivalent to a LOLP of 0.0274%, or 2.4 hours per year).⁷

Ancillary Services

The need for ancillary services⁸ in each portfolio is based on the relationship between the minute-to-minute variations in NorthWestern’s historical load and generation available from variable renewable resources on the system. The simulation determines how much of the variation in load can be met with resources which can respond within 10 to 15 minutes to increase or decrease their output (i.e. INC or DEC resources), and how much must be met with more expensive regulation resources that can increase or decrease output moment to moment. Ancillary service needs for each portfolio are determined by scaling this relationship to the amount and type of renewable resources in the portfolio in each year.

Structural Relationships between Input Variables

PowerSimm preserves many important correlations and structural relationships historically observed between key input variables. For example, weather conditions drive electric load. Thus, PowerSimm’s simulation engine is based on the assumption that the historically observed relationship between loads and temperatures is a good representation of the likely future relationship between loads and temperatures. The same is true for the relationship between weather and wind generation, solar generation, and hydro generation.

⁷ Note that LOLP can be expressed in a variety of ways, including as a percentage of time, as the number of expected hours per year with a loss of load, or the amount of capacity (MW) short per year.

⁸ Ancillary services are those necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. See Chapter 4 for a complete description.

PowerSimm does not assume that historical electricity price patterns continue unchanged because price levels and price variability have both changed in recent years. This change is attributable to the growing penetration of variable renewable resources. Based on numerous analyses of power systems across the country and in the WECC, Ascend Analytics (the developer of PowerSimm) expects the continued development of renewable resources, which will continue to put downward pressure on energy prices (since they have zero variable cost) in the WECC and increase the volatility of energy prices. Ascend anticipates these trends will continue in the WECC, therefore PowerSimm simulations are based on assumptions of decreasing average prices (and, thus, decreasing implied market heat rates) and increasing price volatility. Ascend also anticipates continuing changes in the daily price shape, which is now driven by net load. Net load is gross loads minus generation from renewables.

Carbon Costs

Two separate carbon scenarios are considered in the 2019 Plan. For the base carbon scenario, NorthWestern relied on the carbon costs included in the NEM Study conducted by Navigant Consulting. For the High-cost carbon price scenario, NorthWestern relied upon the carbon price forecast from the 2015 Plan, but delayed implementation by three years.⁹

Modeled Resource Portfolios

Even though resource acquisition will be based on a competitive proposal solicitation process or, in the case of opportunity resources, in a manner consistent with resource

⁹ The development of carbon costs is discussed in Chapter 9.

planning methodologies, NorthWestern is required to identify an optimal resource mix given the goals and objectives of the resource planning guidelines (ARM 38.5.82213, 1(h)). In past resource plans, resource portfolios provided varying degrees of resource adequacy, or reserve margins. The result was that comparison of resource adequacy and cost between different portfolios was not possible. In the 2019 Plan, NorthWestern uses the ARS module to add resources to achieve the same level of resource adequacy for each portfolio, this allows for an “apples-to-apples” comparison between portfolios.¹⁰ Table 10-1 lists the assumptions for each portfolio modeled in the 2019 Plan and a short description of each portfolio follows the table.

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¹⁰ Each portfolio except the Current portfolio.

Table 10-1. Resource Portfolios and Assumptions

Resource Portfolio	Portfolio Assumptions
Current	<ul style="list-style-type: none"> • 20 year planning horizon • Life cycle capital cost recovery • No carbon cost • N-gas forward market prices based upon forward market prices and EIA-AEO Henry Hub escalation • Forward market electricity prices with declining market heat rates and increased volatility
Unconstrained Expansion	Current , with unconstrained ARS
Base	Current , with constrained ARS
Pumped Hydro	Current , 100 MW pumped hydro storage, constrained ARS
Wind	Current , plus 210 MW wind, constrained ARS
Solar PV	Current , plus 210 MW solar PV, constrained ARS
Li-Ion Battery	Current , 105 MW Li-Ion battery storage, constrained ARS
Carbon Cost	Base , with carbon cost adder
High Carbon Cost	Base , with high carbon costs
High Natural Gas Prices	Base , with high natural gas prices
No Carbon Additions	Current , with constrained ARS, limited to non-carbon producing resources
Short Term Current	Current , but with 15 year planning horizon and <ul style="list-style-type: none"> • 15 year planning horizon • 15 year capital cost recovery
Short Term Base	Short Term Current , with constrained ARS

Current: This portfolio models the resource portfolio as it currently exists and does not add any new resources to the portfolio. Natural gas prices are based on forward natural gas prices and 2018 AEO escalation. Forward electric market prices reflect declining market heat rates and increased price volatility. Additionally, the Current portfolio does not include an explicit carbon cost adder.

NorthWestern Energy is continuing its use of a 20-year planning horizon and a life-cycle approach to capital cost recovery in the 2019 Plan.¹¹ The Current portfolio serves as the base for all other portfolios.

Unconstrained Expansion: This portfolio is based upon the Current portfolio assumptions and adds new resources using an unconstrained ARS analysis to achieve a 16% reserve margin.

Base: This portfolio is based upon the Current portfolio assumptions and adds new resources to the portfolio using constrained ARS analysis. Constrained ARS analysis adds about 200 MW of capacity (peaking contribution) per year from 2022 through 2025 to achieve a 16% reserve margin.

Pumped Hydro: This portfolio is based upon the Current portfolio assumptions and adds 100 MW of pumped hydro in 2026.¹² After pumped hydro, additional resources were selected using constrained ARS analysis.

Wind: This portfolio is based upon the Current portfolio assumptions and adds 210 MW of wind in 2022. After wind is added, additional resources were selected using constrained ARS analysis.

Solar: This portfolio is based upon the Current portfolio assumptions and adds 210 MWs

¹¹ The Default Electricity Supplier Procurement Guidelines define “planning horizon” as the longer of the longest remaining contract in the portfolio, the longest lived resource being considered, or ten years; Admin R. Mont. 38.5.8202.

¹² 2026 is assumed to be the first year that a pumped hydro facility could be in-service following the filing of this plan and allowing time for a competitive solicitation process and construction of the resource.

of solar PV in 2022. After solar was added to the portfolio, additional resources were selected using constrained ARS analysis.

Li-Ion: This portfolio is based upon the Current portfolio assumptions and adds 105 MWs of Li-ion batteries in 2022. After Li-ion batteries were added to the portfolio, additional resources were selected using constrained ARS analysis.

Carbon Cost: This portfolio includes all the assumptions of the Base portfolio and adds carbon costs. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis.

High Carbon Cost: This portfolio includes all the assumptions of the Base portfolio and increases the cost of carbon above those contained in the Carbon Cost analysis. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis.

High Natural Gas Prices: This portfolio includes all the assumptions of the Base portfolio except natural gas prices are escalated at 150% of the Base case escalation. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis.

No Carbon Additions: This portfolio is based on the Current portfolio, but ARS analysis was limited to the selection of non-carbon producing resources. As in the Base portfolio, resources were added to the portfolio using constrained ARS analysis, but in this portfolio the analysis is limited to the selection of non-carbon producing resources.

Short Term Current: The Commission's comments requested a 15 year planning horizon, and two portfolios are based on a shortened 15 year analysis. This portfolio is based on the Current portfolio, but the planning horizon is limited to 15 years.

Short Term Base: This portfolio includes the assumptions of the Short Term Current portfolio, but includes a 15-year capital cost recovery for new resources selected by constrained ARS analysis.

PowerSimm Modeling and Results of Analysis

The resource portfolios listed in Table 10-1 were modeled using the PowerSimm hourly model described earlier in this chapter. The results are presented in tables showing resource additions, and in graphical form showing the net present value (NPV) of the revenue requirement of each portfolio and the associated carbon intensity. Most portfolios shown add resources using ARS analysis to achieve a 16% reserve margin. The exceptions are the Current and Current Short Term portfolios, which do not achieve a reserve margin and are not comparable to other portfolios. Additionally, the short term portfolios are not comparable to longer term portfolios, short term portfolios are an NPV of 15 years of revenue requirement while longer term portfolios are an NPV of 20 years of revenue requirement.

Current, Unconstrained Expansion, and Base Portfolios

Table 10-2 and Figure 10-1 show PowerSimm modeling results for the Current, Unconstrained, and Base portfolios. As previously mentioned, the Current portfolio is not comparable to other portfolios because it does not add new resources or achieve resource adequacy. Using an unconstrained ARS process, the analysis adds 716 MW of thermal resources in 2022 with a total of about 930 MW of thermal over the 20 year planning horizon. This rate of resource acquisition is unrealistic. ARS for the Base portfolio was constrained and adds 193 MW of thermal resources in 2022, 189 MW of thermal resources in 2023, 189 MW of thermal resources in 2024, 207 MW of thermal resources in 2025 (778

MW in four years), and a total of about 985 MW of thermal resources over the 20 year planning horizon.

Table 10-2. Unconstrained and Base Portfolios - ARS Resource Selection

Resource	Portfolio		
	Current (MW)	Unconstrained Expansion (MW)	Base (MW)
105 MW Solar	0	0	0
105 MW Wind	0	0	0
100 MW Pumped Hydro	0	0	0
26.3 MW Li-ion Battery	0	0	0
25 MW Aero	0	525	0
18 MW Rice	0	162	738
9 MW Rice	0	180	189
19.4 MW Rice - DGGs	0	58.2	58.2
Total Additions:*	0	925.2	985.2

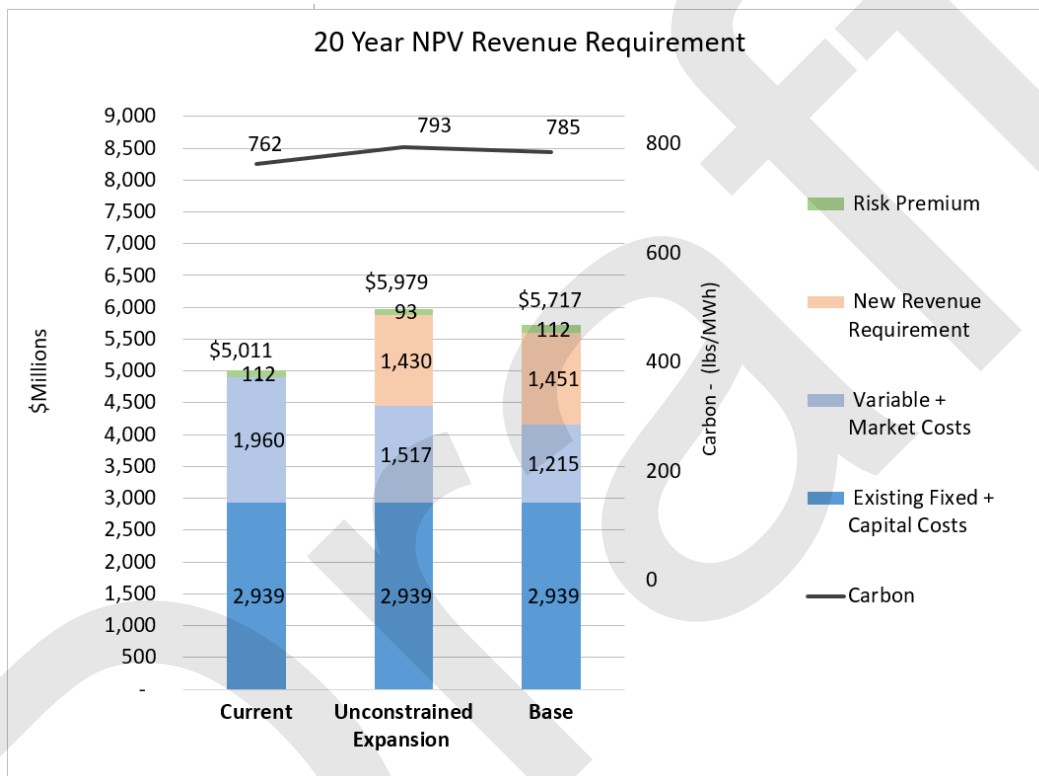
* Portfolio additions over 20 year planning horizon

The ARS analysis in this Plan generally selects natural gas fired thermal generation. However, no one reading this plan should jump to the conclusion that NorthWestern is planning to acquire natural gas fired generation without first testing the market and soliciting proposals for resources (existing and new build) capable of reliably serving our customers’ needs at lower cost. For a further discussion of NorthWestern’s resource additions strategy, please see Chapter 11.

As shown in Figure 10-1, compared to the Current portfolio the Base portfolio adds about \$1.4 billion of capital investment and fixed O&M costs to the portfolio while reducing variable and market costs by about \$443 million. The risk-adjusted NPV revenue requirement of the Unconstrained Expansion portfolio is about \$262 million higher than the Base portfolio. The average annual carbon intensity (lbs of CO₂/MWh) of each

portfolio is represented by the black line and increases due to the additional thermal resources ARS adds to the resource portfolio.

Figure 10-1. Net Present Value Revenue Requirement for Current, Unconstrained, and Base Portfolios



Base, Pumped Hydro, Wind, Solar PV and Li-ion Battery Portfolios

Table 10-3 and Figure 10-2 show PowerSimm modeling results for the Base, Pumped Hydro, Wind, Solar PV and Li-ion Battery portfolios. ARS analysis for the Base portfolio did not select wind, solar PV, pumped hydro, or Li-ion battery technologies, even when low-cost futures for wind, solar PV, and Li-ion (see Figure 7-2) were included for selection in the ARS model.

For the Pumped Hydro portfolio, 100 MW of generic pumped hydro storage was added to

the resource portfolio in 2024. The remainder of the resource portfolio was then selected using ARS. The 100 MW pumped hydro addition offsets about 100 MW of thermal resources, but 210 MW of additional wind is also selected because pumped hydro doesn't provide for customers' energy needs. The Pumped Hydro portfolio has a lower carbon intensity than the Base portfolio (716 lbs/MWh vs. 785 lbs/MWh) but the risk-adjusted NPV is \$206 million more than Base.

Table 10-3. Base, Pumped Hydro, Wind, Solar PV, and Li-ion Portfolios ARS Resource Selection

Resource	Portfolio				
	Base (MW)	Pumped Hydro (MW)	Wind (MW)	Solar (MW)	Li-ion Battery (MW)
105 MW Solar	0	0	0	210	0
105 MW Wind	0	210	210	105	0
100 MW Pumped Hydro	0	100	0	0	0
26.3 MW Li-ion Battery	0	0	0	0	105.2
18 MW Rice	738	828	936	720	828
9 MW Rice	189	0	0	198	0
19.4 MW Rice - DGGS	58.2	58.2	58.2	58.2	58.2
Total Additions:*	985.2	1196.2	1204.2	1291.2	991.4
*Portfolio additions over 20 year planning horizon.					

In the Wind portfolio, 210 MW of wind was added to the resource portfolio in 2022. The remainder of the resource portfolio was then selected using ARS. Because of its low capacity contribution during peak load hours, 210 MW of wind does not offset the capacity required from thermal generation resources. The Wind portfolio does have a lower carbon intensity than the Base portfolio (715 lbs/MWh vs. 785 lbs/MWh) because the energy from wind generation does offset the energy from thermal generation, but the risk-adjusted NPV is \$176 million more than Base.

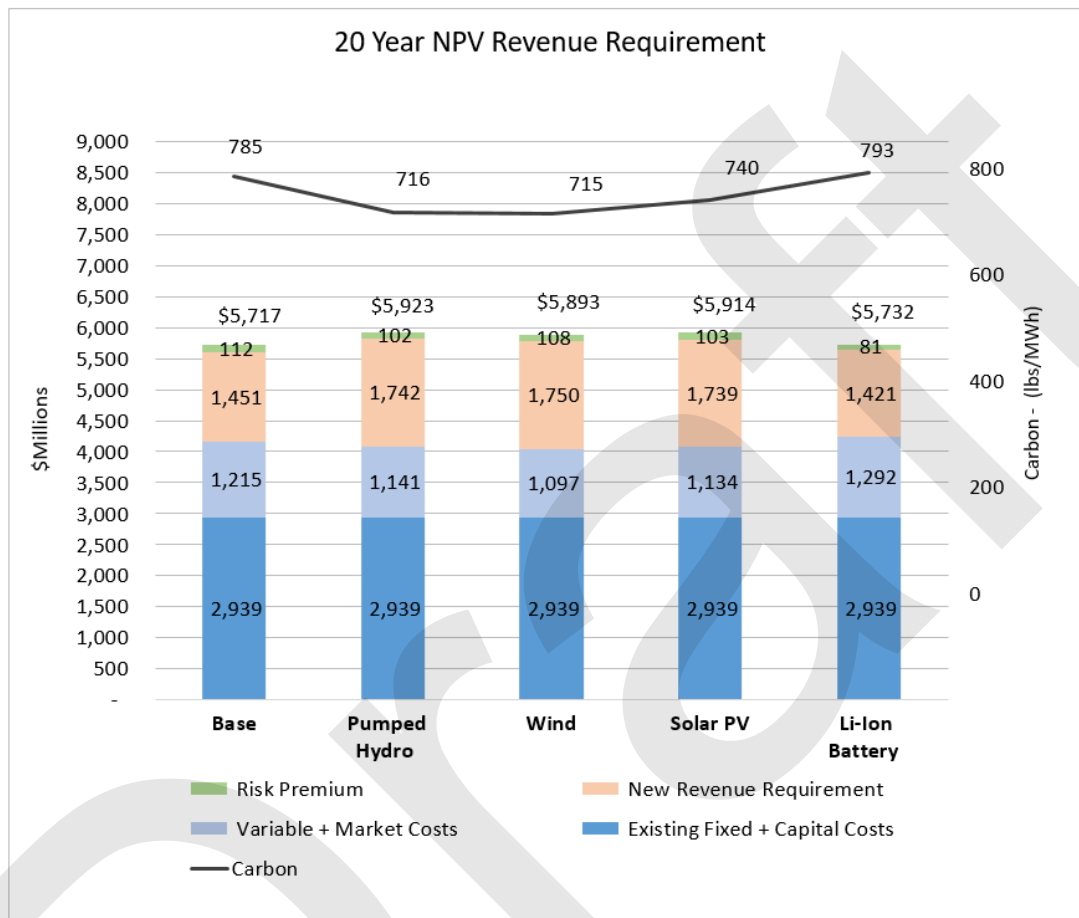
In the Solar PV portfolio, 210 MW of solar PV was added to the resource portfolio in 2022.

The remainder of the resource portfolio was then selected using ARS. Because solar PV does not contribute to the capacity required during NorthWestern’s winter peak load hours, Solar PV does not offset any of the thermal resources. The Solar PV portfolio has a lower carbon intensity than the Base portfolio (740 lbs/MWh vs. 785 lbs/MWh) but the risk-adjusted NPV is \$197 million more.

For the Li-ion Battery portfolio, 105 MW of Li-ion battery storage is added to the resource portfolio in 2022. The remainder of the resource portfolio was then selected using ARS. The addition of 105 MW of Li-ion battery storage offsets 90 MW of the thermal resources selected from 2022 to 2025 in the Base portfolio. The Li-ion Battery portfolio has a higher carbon intensity than the Base portfolio (793 lbs/MWh vs. 785 lbs/MWh) and the risk-adjusted NPV is \$15 million more.

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Figure 10-2. Net Present Value Revenue Requirement for Base, Pumped Hydro, Wind, Solar, and Li-ion Battery Portfolios



Base, Carbon Cost, High Carbon Cost, and High Natural Gas Prices, No Carbon Additions Portfolios

Table 10-4 and Figure 10-3 show PowerSimm modeling results for the Base, Carbon Cost, High Carbon Cost, High Natural Gas Prices, and No Carbon Additions portfolios. The Base portfolio has been included for comparison and is discussed above. The remaining portfolios in this section are scenarios designed to test resource selection under various futures (or scenarios). The Carbon Cost scenario tests the selection of resources when a

cost for carbon is included in the analysis.¹³ The High Carbon Cost scenario tests the selection of resources at a higher carbon cost. The High Natural Gas Costs scenario tests whether high gas costs affect resource selection. Lastly, the No New Carbon scenario explores what resources are selected if ARS analysis is limited to the selection of non-carbon producing resources.

The results of ARS selection are shown in Table 10-4. The addition of a carbon cost does little to affect thermal resource selection in the Carbon Cost, High Carbon Cost, and High Natural Gas Prices scenarios. However, the High Cost Carbon scenario adds 420 MW of wind resources over the 20 year planning horizon. The High Natural Gas Prices scenario had no effect on resource selection.

Table 10-4. ARS Selection Under Various Conditions

Resource	Portfolio				
	Base (MW)	Carbon Cost (MW)	High Carbon Cost (MW)	High Natural Gas Prices (MW)	No Carbon Additions (MW)
105 MW Wind	0	0	420	0	1680
100 MW Pumped Hydro	0	0	0	0	300
26.3 MW Li-ion Battery	0	0	0	0	631.2
18 MW Rice	738	702	756	738	0
9 MW Rice	189	216	162	189	0
19.4 MW Rice - DGGS	58.2	58.2	58.2	58.2	0
Total Additions:*	985.2	976.2	1396.2	985.2	2611.2

* Portfolio additions over 20 year planning horizon

The No Carbon Additions scenario does result in a significant change in the resources selected in ARS analysis. When thermal generation is excluded, the ARS selects 1,680 MW of wind, 300 MW of pumped hydro, and 631 MW of Li-ion batteries. The carbon

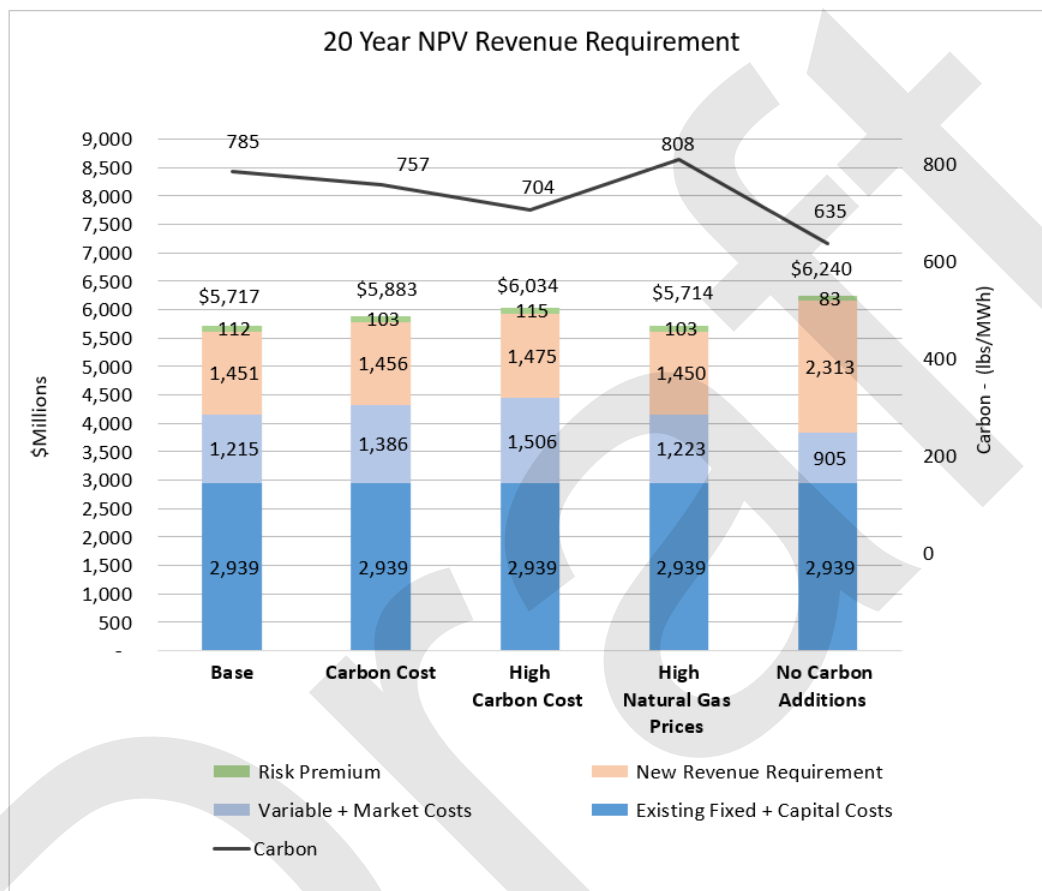
¹³ The development of the carbon cost is discussed in Chapter 9.

intensity is lower (635 lbs/MWh vs. 785 lbs/MWh), but at a significant cost. As shown in Figure 10-3 below, the risk-adjusted NPV of the No Carbon Additions is \$523 million more than that of the Base portfolio.

Other significant non-quantified costs are incurred with a No Carbon Additions scenario. For example, the footprint of nearly 1,700 MW of wind is estimated to be 300 to 350 square miles. Siting that much wind in Montana could be problematic and the NPV costs do not include any infrastructure costs, such as upgrades and additions to the electric transmission system, which would be required to add that much wind to the system. The current largest Li-ion battery installation in the US is a 30 MW/120MWh facility; 631 MW of Li-ion batteries would require over 20 similar sized facilities. While the Li-ion battery facilities could be spread around NorthWestern's system, each one would require a total of about 1.5 acres. Lastly, the 300 MW of Pumped Hydro that ARS selected does not include any potential transmission upgrade costs that may be required.

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Figure 10-3. Net Present Value Revenue Requirement for Base, Carbon Cost, High Carbon Cost, High Natural Gas Prices, and No Carbon Additions Portfolios

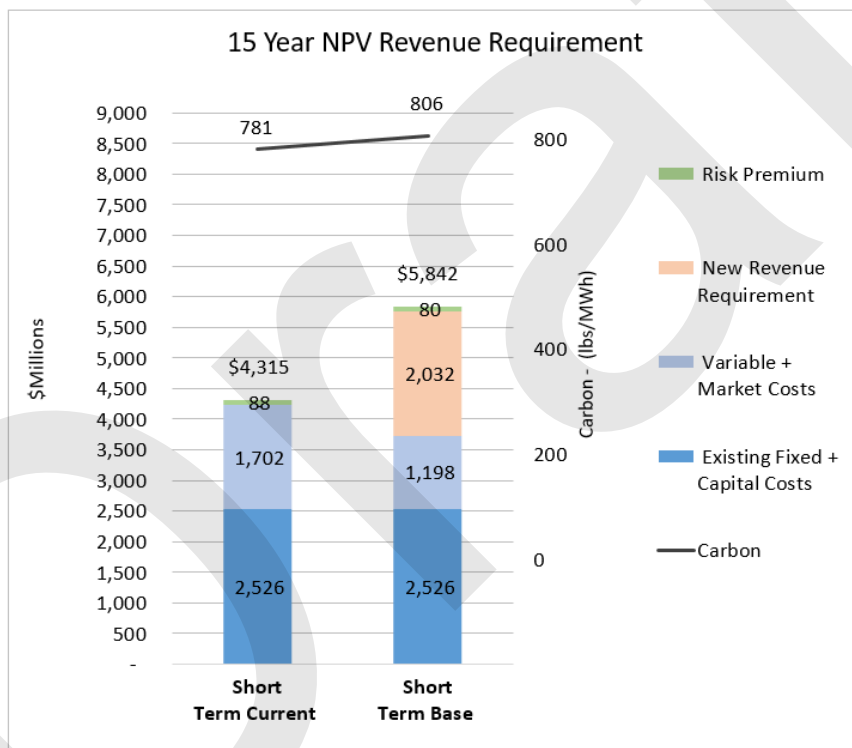


The Carbon Cost, High Carbon Cost, and High Natural Gas portfolios to test the resource selection of the ARS under Base portfolio assumptions. The Base, Carbon Cost and High Natural Gas portfolios all add similar amounts of natural gas fired resources to the portfolio. The High Carbon Cost portfolio selects a little less natural gas and also selects some wind. The Carbon Cost NPV is about \$166 million more than the Base portfolio, the High Carbon Cost NPV is about \$317 million more than the Base portfolio, and the High Natural Gas NPV is about \$3 million less than the Base portfolio.

Short Term Current and Short Term Base Portfolios

Figure 10-4 shows PowerSimm modeling results for the Short Term Current and Short Term Base portfolios. The Short Term Base portfolio has the lowest NPV revenue requirement, but has the highest rate impact. As stated earlier, the 15 year portfolios are not comparable to the 20 year portfolios.

Figure 10-4. Net Present Value Revenue Requirement for Short Term Current and Short Term Base Portfolios

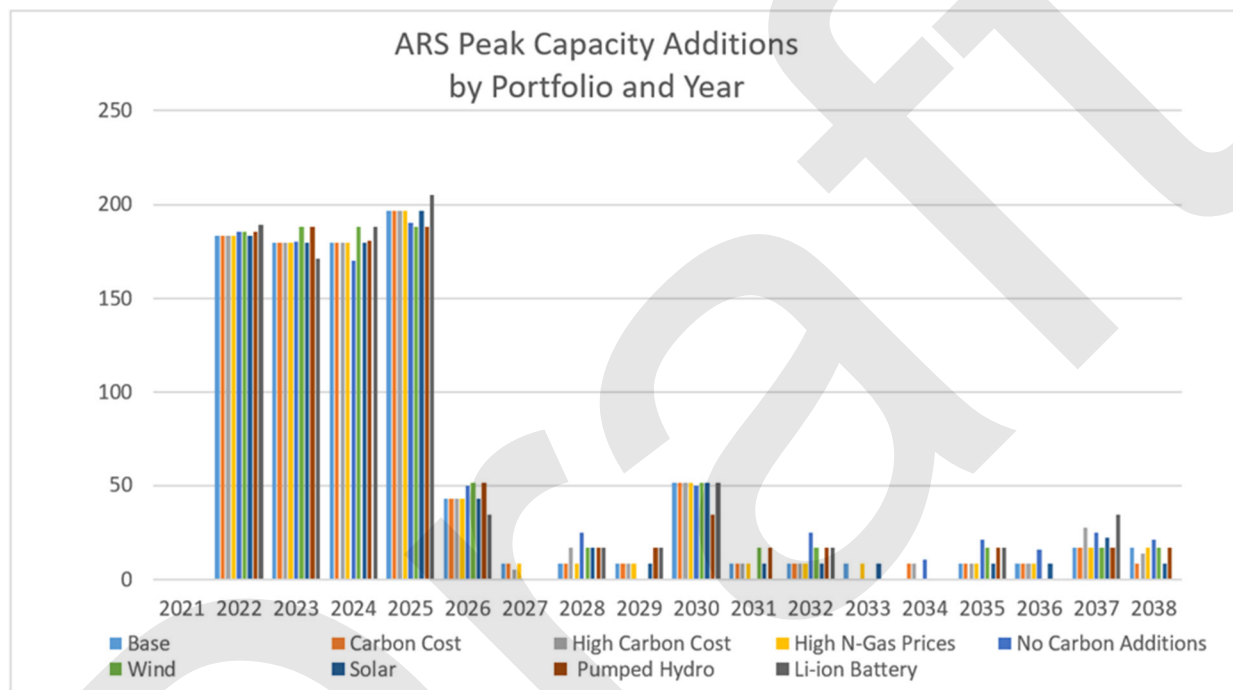


ARS Portfolio Additions

Figure 10-5 shows the ARS peak capacity additions by year for each portfolio except the Short Term Current and Short Term Base portfolios. The chart shows that constrained ARS adds approximately the same quantity of peaking capacity to each portfolio

throughout the planning horizon. The Unconstrained portfolio was excluded from this chart due to its unrealistic schedule of buildout. The 15 year Short Term Base was excluded because the 15 year portfolios are not comparable to the 20 year portfolios.

Figure 10-5. ARS Peak Capacity Additions by Portfolio and Year

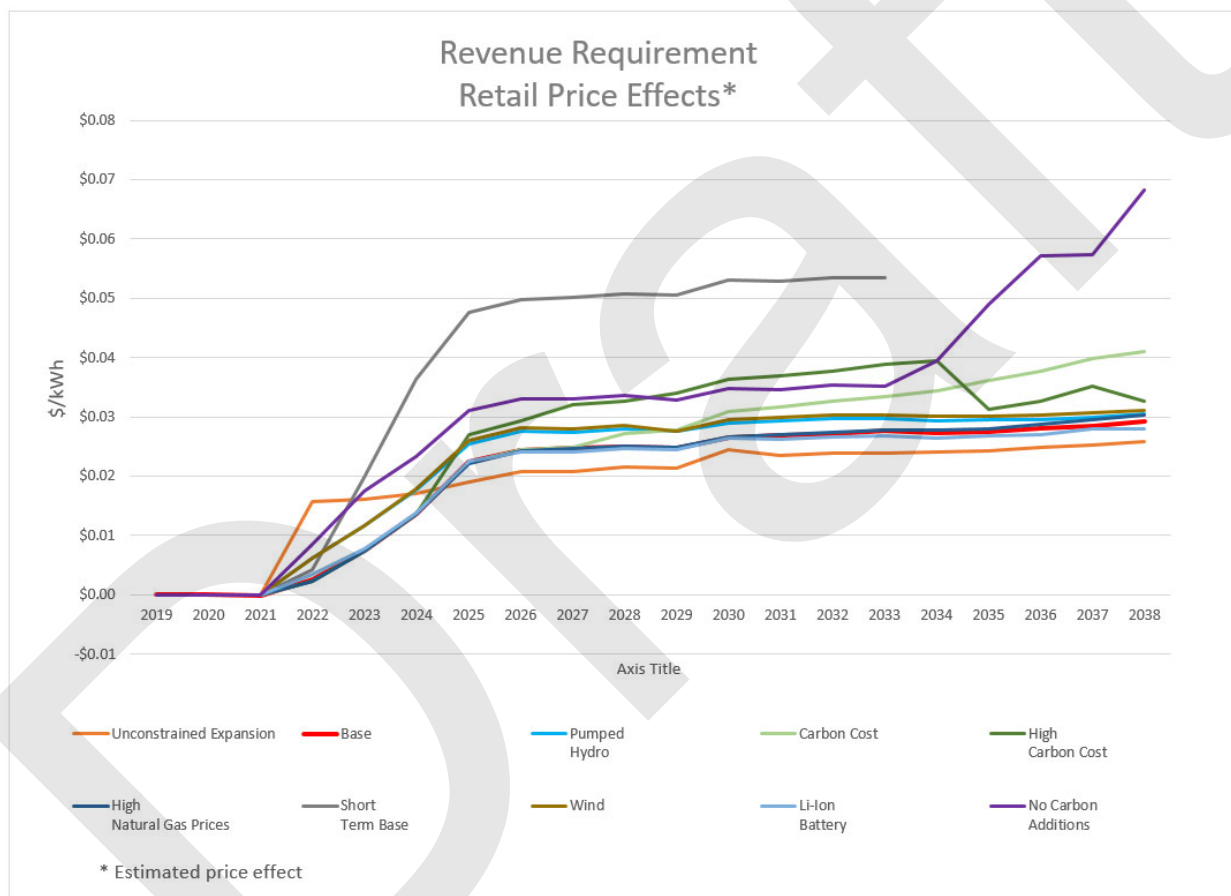


Estimate Retail Rate Impacts

Figure 10-6 below shows the estimated retail energy price impact of each portfolio throughout the planning horizon. Many of the portfolios show similar rate impacts due to the fact that all portfolios shown achieve the same level of resource adequacy. The highest initial, but lowest long term, rate impact is the Unconstrained portfolio. The Li-ion Battery, Base, High Natural Gas Prices, Carbon Cost, and High Carbon Cost portfolios are grouped very close together until the Carbon Cost and High Carbon Cost portfolio diverge in about 2024. A second tight grouping occurs, consisting of the Wind, Pumped Hydro (hidden by Wind) and Solar PV portfolios. The No Carbon Additions portfolio has a higher retail

price impact which becomes very high towards the end of the planning horizon as about 1,700 MW of wind are added to the portfolio.¹⁴ The Short Term Base portfolio had the lowest NPV revenue requirement, but has the highest retail price impact due to the recovery of investment over a shorter period of time.

Figure 10-6. Estimated Retail Impacts by Portfolio



¹⁴ This aligns with the findings of the regional study “Resource Adequacy in the Pacific Northwest” conducted by Energy + Environmental Economics (E3). The study is scheduled to be released March 2019.

Conclusion

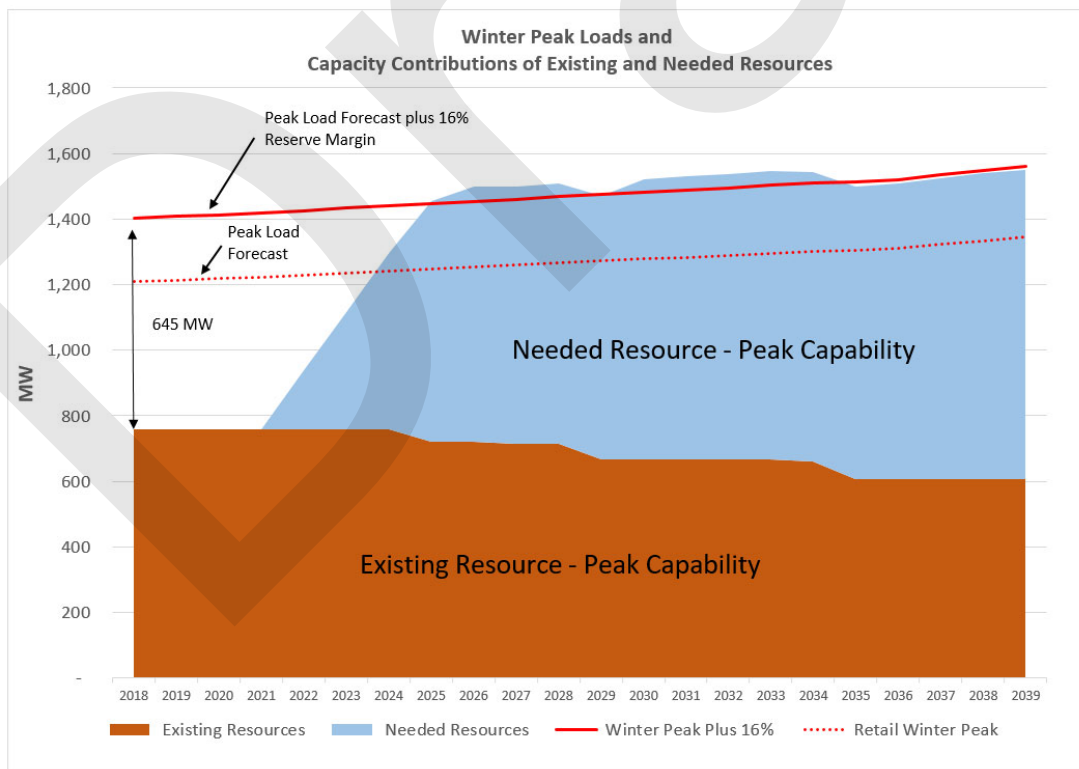
The portfolio models discussed in this chapter should be regarded as indicative of which resources could be used to meet the future resource needs of customers at lowest total cost. Even though portfolio modeling and analysis identifies specific resources and specific portfolios, NorthWestern’s energy procurement strategy will rely on competitive solicitations of proposals, also known as Requests for Proposals (RFPs). The model and modeling framework used in this plan will be used to evaluate proposals submitted during competitive solicitations and will also be used to evaluate opportunity purchases.

CHAPTER 11 PORTFOLIO ADDITIONS STRATEGY AND ACTION PLAN

NorthWestern’s Portfolio Additions Strategy

This chapter describes the strategy and action plan NorthWestern will use when considering additions to our supply portfolio. Figure 11-1 below illustrates the peak load forecasts, the capacity contributions of existing resources, and the additional capacity contributions needed to mitigate market risk and to participate in a full market by 2025.

Figure 11-1. Additional need for Peaking Capacity



NorthWestern Energy’s current resources provide about 755 MW of peaking capacity, which is the energy available during periods of our customers’ highest demand. An additional 645 MW of peaking capacity must currently be purchased from the market to meet our needs. Without new peaking capacity, the market exposure will increase to about 725 MW by 2025 (including reserve margins). This peaking need assumes continued development of cost-effective demand side management (conservation) and small distributed generators (net-metering).

The figure illustrates the need for NorthWestern to begin arranging for peaking capacity resources. Resource additions are shown to begin in 2022 because that is the soonest timeframe in which NorthWestern could file the 2019 Plan, conduct a competitive solicitation of proposals, and allow for construction should new-build resources win the solicitation. NorthWestern Energy will solicit competitive proposals from a variety of resources and use a staged approach, adding approximately 200 MWs of capacity per year, beginning in 2022. NorthWestern Energy will evaluate all cost-effective resources including power purchase agreements and owned energy resources comprised of different structures, terms, and technologies with the long term objective of a clean, stable, and reliable energy portfolio. The staged approach allows for incremental steps through time with opportunities for different resource types and new technologies while also building a reliable portfolio to meet local and regional conditions and minimizing customer impacts.

Resource Acquisitions Strategy

Competitive Solicitations of Proposals for Resource Acquisitions

ARM 38.5.8212(2) states that a utility should use competitive solicitations with short-list negotiations as a preferred procurement method. Although opportunity resources may be

obtained outside of a competitive solicitation, NorthWestern intends to procure the resource needs of customers through competitive solicitations.¹² Solicitations for proposals will be staged so that no more than about 200 MWs of new resources are added to the portfolio in any one RFP process.

The RFP process may result in the acquisition of resources identified in the modeling conducted for this plan; however, it is more likely resources that were not identified or modeled, or could not be identified during the planning process, will be acquired. For example, NorthWestern issued a Request for Interest (RFI) that identified a number of new and existing resources that could potentially be acquired, but the RFI did not result in resource definitions for inclusion in the modeling portion of the plan, but did provide validation of the resource definitions provided by HDR.³

Request for Proposal (RFP) Process

In compliance with Montana statutes under SS 69-8-419, MCA and Commission rules under ARM 38.5.8212, any future RFP will focus on the most reliable, lowest long-term cost bids that meet NorthWestern’s identified resource needs, and could include the following types of resources:

- Sale of all or part of existing resources
- Engineer, procure and construct project at the DGGS facility
- New generation resources including,

¹ Opportunity resources are those generation resources, either existing or new-build, which remain unknown as to their availability until an opportunity to purchase arises. Opportunity resources cannot be known or modeled in a resource planning process, but will be evaluated in a manner consistent with portfolio evaluations in the 2019 Plan.

² Competitive solicitations are generally fulfilled using a Request-for-Proposal (RFP) process.

³ The RFI responses did provide validation of the new build resource options included in HDR’s resource definitions study (Chapter 7).

- Solar generation combined with storage,
- Wind generation combined with storage,
- Natural Gas-fired generation,
- Other generation technologies, including hydro,
- Energy storage technologies, including,
 - Pumped hydro energy storage,
 - Battery storage technologies, and
 - Compressed air energy storage,
- Demand response resources under automated control.

As with the 2017 Flexible Capacity RFP, NorthWestern intends to use an independent, third-party administrator to conduct any future RFP process. In order to ensure equitable treatment of each proposal, the RFP Administrator will be instructed to not identify any bidders by name until the resources have been selected for final negotiations. The RFP will be publicly noticed and sent to any party expressing a desire to receive one, and to developers that NorthWestern is aware of from prior solicitations. The RFP will request the following information.

- Projects must demonstrate that they have a proven safety record.
- Proposals will be evaluated using the modeling contained in the 2019 Plan to determine the value that proposed project provide to customers.
- Projects must the ability to demonstrate they are from a bidder that can complete its proposed project on the timeline contained in the proposal.
- Developers should have completed similar projects, or at a minimum, demonstrate that capital markets support the project.
- Developers must demonstrate the financial worthiness to perform.

Opportunity Resources

Opportunity resources are those resources that NorthWestern cannot foresee or model in a resource planning process. Typically, opportunity resources are existing assets that become available for acquisition on short notice and with a short time-frame for transaction completion. Usually the owner (or owners) of opportunity resources control the process, usually their own RFP process, and NorthWestern has no control over that process. NorthWestern evaluates opportunity resources in a manner consistent with the methodologies contained in the most current resource plan to determine if the opportunity resource could fill a portfolio need in an economical manner.

Action Plan

Action Plan Items

- 1. Regional Market Transformation:** NorthWestern has committed to join the Western EIM in 2021 and will continue to work toward that goal. NorthWestern will also participate in the developing energy day-ahead market discussions and will continue to monitor and participate in the development of proposed RTOs/ISOs.
- 2. Competitive Solicitation:** As explained above, NorthWestern will conduct an RFP process using an independent administrator to initially acquire up to 200 MW of flexible capacity, which is only about one-fourth of NorthWestern's projected need in order to meet its reserve margin requirement. NorthWestern plans to follow with additional competitive solicitation, reassessing customers' needs, and building upon the information gained from previous solicitations.
- 3. Resource Optimization:** NorthWestern remains committed to the efficient and cost effective optimization of the existing fleet of company-controlled resources. NorthWestern will continue to explore additional improvements to the operational efficiencies of our thermal, hydro, and wind generation resources.

4. **RPS Obligations:** NorthWestern will continue to manage and pursue resources to meet its ongoing RPS and CREP obligations.
5. **Emerging Technologies:** NorthWestern will continue to monitor the development and application of emerging technologies which have the potential to help meet our customer's future energy needs
6. **Public Participation in Planning:** NorthWestern will evaluate its processes for providing public participation in its resource planning process. Timing, frequency, location, content of public meetings and the usefulness of the ETAC will be evaluated prior to the next planning process.