CLIMATE SMART
MISSOULA

May 3, 2019

Mr. Robert Rowe, President and CEO NorthWestern Energy 11
E. Park St.
Butte, MT 59701

Dear Mr. Rowe:

We appreciate the opportunity to comment on NorthWestern Energy's Draft 2019 Electricity Supply Resource Procurement Plan.

Climate Smart Missoula is a community non-profit organization which formed in 2015 and whose mission is to engage our community in climate actions, catalyzing efforts to reduce our carbon footprint and build a resilient Missoula. Increasing affordable renewable energy options and reducing our reliance on carbon intensive fossil fuels are critical components of the work we do.

Over the past two years we at Climate Smart Missoula have worked closely with the City of Missoula and Missoula County to develop a 100% Clean Electricity Options Report and Commitment by our elected officials. That report and resolution are available here: https://www.missoulaclimate.org/100percent.html. We are committed to working with the necessary entities in Montana and beyond to fulfill this goal. When the resolution to adopt the 100% clean electricity goal came before the Missoula Board of County Commissioners and the Missoula City Council we were able to demonstrate, via letters and public comment, there is strong public support for this initiative. This support is no doubt growing as we grapple with the threats of climate change and the changing energy landscape. We hope that we can do what other communities around the country who have set similar 100% renewable electricity are doing—that is work directly with the local utilities to achieve this transition. There is an ever-growing list of vertically integrated investor-owned utilities that have committed to achieve 100% carbon-free electricity. Their resource procurement plans are forward thinking and not based on fossil fuels. We believe it is time for NorthWestern Energy to join this list.

As we highlight in our recent Options Report, we believe there are means by which we can add more renewable electricity to the grid, allowing us to get to 100%, given the approximately 60% already considered clean via Northwestern's current portfolio. Yet the question this plan does not adequately answer is, how will Northwestern Energy start planning for and investing in the necessary low-carbon future that is mandated by science, economics and market forces?

The draft plan emphasizes that NorthWestern intends to pursue "lowest cost" resources. We ask that you consider the full, long-term costs of energy resource choices as you make procurement decisions. We do not see an acknowledgment of the long- term costs of climate change. Additionally, myriad studies show conclusively that over the long-term, a transition to more renewables will save money. The price of solar and wind as energy resources has declined dramatically in recent years. Pair this with the fast-declining costs of battery storage technologies, and this path is increasingly obvious. We are especially concerned with the costs of construction of gas-fired power plants and gas pipelines relative to renewable energy infrastructure.

Response: This issue is addressed in NorthWestern's response to public comments in Chapter 11.

The final procurement plan should clearly model the costs of running existing power plants in the portfolio compared to other clean electricity options. We ask that NorthWestern provide the details regarding what costs have been assigned to existing power plants. Further, we ask that the final plans detail how existing facilities have been evaluated for cost-effectiveness against other options. As far as we can tell, it remains unclear how we ratepayers can know we are receiving the least-cost energy since existing power plants are never evaluated for cost-effectiveness.

Response: This recommendation is not consistent with resource planning statutes or rules. Please see NorthWestern's response to public comments in Chapter 11.

Finally, and importantly we add are voice to those requesting that the final plan model a scenario where the Colstrip power plant retires in 2025 or soon thereafter. Planning that assumes Colstrip continues on for decades undermines the least-cost arguments of the plan, exposes ratepayers to short-term decision-making by NorthWestern Energy, and exposes all to the risk of paying too much for energy. We are working hard here in Missoula on issues of energy equity, and passing costs to local ratepayers is of significant concern.

Response to comment: this is discussed in Chapter 11 Public Comments.

Resource procurement form NorthWestern Energy matters to all of us. We all deserve a livable planet where clean energy and the health of local communities are prioritized. We look forward to a final plan that addresses these concerns and those of other communities and ratepayers.

Thank you for again for the opportunity to provide our perspectives. We look forward to learning how the revised Resource Procurement Plan can catalyze our broadly supported transition to clean electricity.

Most sincerely,

Amy Cilimburg, Executive Director
Climate Smart Missoula amy@climatesmartmissoula.org
406-926-2847

As a state-wide organization focused on empowering young Montanans, Forward Montana spends a lot of time thinking about how best to meet the challenges young people face in our state. Among the biggest challenges our generation increasingly has to contend with are climate change and economic stability. As we graduate high school and college and begin to build our lives, climate change is creating an increasingly chaotic backdrop. It is also becoming more difficult to access good-paying jobs and find affordable prices for housing and other basic necessities.

We recognize that providing reliable power to ratepayers is a challenging task as well. In moving forward, we urge you to seriously investigate a path forward that meets both the challenge of providing low-cost, reliable energy to customers and the challenge of rapidly scaling back our state's dependence on fossil fuels in the next 10-12 years. We see the latter goal as an essential stepping stone for reaching the former.

Given the scientific consensus on climate change, the economic and social consequences detailed in the conclusions of the 2018 IPCC Special Report (https://report.ipcc.ch/sr15/pdf/sr15_spm_final.pdf) and the Fourth National Climate Assessment (https://www.globalchange.gov/nca4), and the likelihood of new state and federal regulation of greenhouse gases, it is very difficult to imagine that climate change will not have a significant effect on NorthWestern Energy's ability to "provide adequate and reliable electricity supply service at the lowest long-term total cost," as required by MCA 69-8-419.

We strongly urge you to look for creative paths forward that prioritize both the goal of providing low-cost energy to ratepayers and the goal of sourcing from new and existing renewable energy infrastructure in place of further investments in coal or natural gas. We hope you will rise to this challenge with creativity, foresight, and with full assessment of how other utilities have approached the challenge of meeting peak load in light of climate change.

After looking over your draft resource procurement plan, we have several bigger-picture questions we'd like to highlight:

1. As a company, what is your position on addressing climate change? Would you be willing to make a public statement addressing the science of climate change?

Response: The comment is outside of the scope of the 2019 resource planning process. The 2019 Plan makes no statement addressing the science of climate change, but did model a "Carbon Cost" and "High Carbon Cost" scenarios. NorthWestern's portfolio of resources generate 70% of its annual energy from non-carbon emitting resources.

2. How do you plan to work with community groups and Montana cities, like Missoula, that are aiming to transition to 100% clean electricity in the next 10-20 years?

Response: This comment is not best addressed in an overall resource plan, or resource planning process, and is not addressed in the 2019 Plan. However, NorthWestern does plan to work with cities like Missoula to help them meet their climate goals.

3. Have you assessed other utilities' approaches to limiting greenhouse gas emissions and setting target dates for reaching 100% clean energy?

Response: The comment is outside of the scope of the planning process and the 2019 Plan.

4. Have you done any analysis on the impact of past and future climate-motivated legislation on existing and recent coal and natural gas resources? Have you assessed the likelihood that new natural gas plants would become stranded assets?

Response: NorthWestern did not include a "stranded asset" risk assessment for new natural gas-fired generation in its resource plan.

5. Do you plan on reaching out to existing hydropower sources and existing storage facilities like Gordon Butte to meet any shortfalls in energy?

Response: As discussed in Chapter 13, NorthWestern will conduct a competitive solicitation for resources, in which resources like Gordon Butte will have an opportunity to bid.

6. The authors of the plan state that battery storage is cost prohibitive. Over what time horizon are you calculating this cost? What particular battery storage options have you considered? Have you considered the long-term cost of "bridging" with various existing resources while waiting for battery storage prices to further decline? How does the cost of purchasing battery storage technology at current prices compare with the long-term cost of Colstrip, including cleanup costs?

Response: Refer to the additional discussion of "low cost futures" at the end of Chapter 7.

7. What is your assessment of how much capacity new power plants will add to the regional energy supply?

Response: The issue of the extent to which NorthWestern will be able to continue to rely on regional capacity is discussed in Chapter 11.

8. The term "cost" is used repeatedly in the plan but never explained. Please explain how you are calculating lowest cost: over what time horizon and for whom?

Response: NorthWestern has an obligation to provide adequate and reliable electricity service at the lowest long-term lowest cost. Lowest cost will be determined using competitive procurement practices whenever possible.

9. When you conclude that "thermal resources provide the best value (lowest cost) to meet our

customers' future needs for peak capacity" on page 1-12, are you considering the ecological cost of natural gas production or the social and ecological cost of greenhouse gas emissions? Have you done any assessment of the externalized costs of various resources?

Response: NorthWestern did not include the costs of externalities, other than costs already reflected in electricity and natural gas prices and costs reflected in new-build costs of resources.

10. Why was Northwestern Energy looking to invest in a larger share of Colstrip this legislative session, and how does that align with the intention to supply energy at a low cost to ratepayers? How do efforts to pass SB 331 relate to this resource supply planning process?

Response: SB 331 was not successful and since the transaction is no longer possible the analysis would not be relevant or meaningful.

11. How do efforts to create a new customer class for rooftop solar customers relate to this resource supply planning process? How would this change impact NorthWestern Energy's ability to meet peak load at lowest cost?

Response: The new customer class referenced has no impact upon the resource plan because NorthWestern must plan for the peak needs of all of its connected customers, and the rooftop solar customers will still represent connected load.

We have several more specific clarifying questions as well:

1. When you conclude on page 1-13 that "[m]eeting 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," which specific projections are you referencing?

Response: NorthWestern was referring to the difference in the NPV revenue requirement of the No New Carbon Additions portfolio to the Base portfolio. Also see Chapter 10.

2. In addressing the statutory requirements of the planning process (as indicated on page 2-1), have you:

i. calculated the "long-term total cost" of various resource options, including projections of which assets might become stranded, potential cleanup costs, and externalized social and ecological costs?

Response: The comment is outside of the scope of the 2019 resource planning process. Externalized social and ecological costs have not been considered within the context of the 2019 Plan.

ii. considered any new "demand side management options" to help reduce peak load? Which new options have you considered, if so?

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 to complete this work, which is expected to be finalized in 2019. The results of these activities may result in adjustments to the forecasts noted in this plan.

iii. considered how climate impacts, like more severe wildfire seasons, might damage infrastructure like poles and wires, and how NorthWestern Energy might manage and mitigate those risks?

Response: This issue has not been considered in the resource plan.

iv. considered the potential costs of procuring a large range of existing and new solar, in combination with and separate from battery storage, for the sake of evaluating the "full range of cost effective electricity supply… management options"?

Response: NorthWestern did not model renewable/storage combinations in its resource plan, but did model them separately. To the extent that battery storage creates synergies with renewables, NorthWestern already has more than enough renewables to create those synergies. Lastly, renewable/storage technologies will be invited to bid into our upcoming solicitation.

3. What is the reasoning for limiting resource additions to "about 200 mW per year" in the ARS analysis (pg 10-3)?

Response: This is the Unconstrained portfolio, which is discussed in Chapter 10. A limit was needed to prevent the model from adding the resources needed to make us resource adequate "all at once" which would have presented a very difficult, if not impossible, build-out schedule.

4. When you state on page 10-14 that the "ARS analysis in this Plan generally selects natural gas fired thermal generation," what exactly are you referring to? As the lowest cost option? Over what time horizon? With what constraints? As opposed to which alternatives, considered in which combination?

Response: Natural Gas-fired generation was selected by ARS as the lowest cost resource to provide capacity at times of system peak loads. The plan will be followed by a competitive solicitation in which all technologies to meet load or reduce it will be evaluated. See Chapter 11 and 13.

5. On page 1-9 and 1-10, you state: "Another concern is that if no additional generation is built to justify keeping the current Colstrip transmission lines, those lines could also be retired…" How significant is this concern, and what are the options for keeping the transmission lines open?

Response: This is a significant concern. The 500 kV system is critical to the reliable operation of the Montana Grid. As noted, the other Colstrip Transmission Owners are not similarly situated as NorthWestern Energy. The CTS 500 kV system is fully integrated into NorthWestern's transmission system. NorthWestern does have the right to purchase the other Colstrip Owners' share of the CTS at the Termination of the Colstrip 3 and 4 Generation Project.

NORTHWESTERN ENERGY
2019 ELECTRICITY SUPPLY
RESOURCE PROCUREMENT PLAN

COMMENTS BEFORE
THE MONTANA PUBLIC SERVICE COMMISSION
SUBMITTED May 4, 2019

GB Energy Park, LLC

I. EXECUTIVE SUMMARY

The following comments are offered by GB Energy Park LLC (GBEP), developer of the Gordon Butte Closed Loop Pumped Storage Hydro Project (Gordon Butte PSH), in response to the NorthWestern Energy 2019 Electricity Supply Resource Procurement Plan's (2019 Plan) assessment of the future power supply needs of NorthWestern Energy (NWE). GBEP is a singlepurpose subsidiary of Montana-based Absaroka Energy Development Group, LLC (Absaroka).

GBEP agrees that given the changes in the electricity markets, additional flexible capacity will be necessary to maintain the long-term health, sustainability, and serviceability of NorthWestern's system. Careful analysis of the 2019 Plan is an important step in ensuring that NWE's customers are provided with the optimum combination of resources to deliver reliable and cost-effective services and ensuring the long-term resiliency of the NorthWestern system.

GBEP offers the comments, observations, questions, and concerns contained within this document to assist NorthWestern in refining the 2019 Plan and subsequent Request For Proposals (RFP), and to more appropriately evaluate and acquire the resources that will best meet their needs.

In general, GBEP's comments on the 2019 Plan can be briefly summarized as follows:

- GBEP does not agree with the conclusion that gas-fired generation resources will provide the most reliable, cost-effective solution to the capacity and flexibility needs identified in the 2019 Plan.
- GBEP engaged an outside expert (see Attachment A) to conduct detailed modeling and analysis of its Gordon Butte Pumped Storage Hydro Project (Gordon Butte PSH) compared to existing rate-based NorthWestern assets (Colstrip 4, Hydro Dams, Spion Kop, and Dave Gates Generation Station). The results show that the advanced pumped storage facility is the **lowest cost choice** for the utility.[1]

Item	DGGS	SPION	Colstrip	Hydro	Gordon Butte
Total Revenue	$29,244,149.00	$11,683,771.0	$77,680,104.00	$142,759,244.00	$72,488,341.54
Capacity [MW]	150	40	222	448	400
Revenue $/kW-yr	$194.96	$292.09	$349.91	$318.66	$181.22

[1] Acelerex. Gordon Butte Rate Base Analysis. May 2019. NOTE: Carbon not considered in analysis. CV for Acelerex available in Attachment A

- The modeling and processes used to create the 2019 Plan **do not adequately measure and/or quantify** the full value and benefits of energy storage assets like the Gordon Butte Pumped Storage Hydro Project. Benefits beyond providing energy – such as grid stability, transmission services, stackable ancillary services, system optimization, and flexible capacity. **This is of particular concern because as NorthWestern states in the 2019 Plan, "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 opportunities purchases."**
- PSH with modern equipment can provide the **regulation duty at a lower cost** than the current portfolio of DGGS, Basin Creek, Colstrip Unit 4, Cochran, Ryan, Mystic, Thompson Falls and other contracted units.
- These existing units should be utilized as energy generating assets – allowing them to operate more reliably and efficiently with a resulting benefit to ratepayers.
- The Gordon Butte PSH facility has been designed to permit an offtaker, such as NorthWestern, to acquire or contract for a portion of the facility that would best suit their needs.
- There are **unanalyzed costs and risk associated** with the development of new gas in the 2019 Plan that have not been identified – development of linear facilities (pipe and transmission lines) for gas will be difficult and potentially unfeasible.

  Risks associated with future carbon assets should be included in the analysis for new resources and must be assessed in an even and fair manner.
- Highly-flexible, utility-scale, long-duration energy storage facilities, like Gordon Butte PSH, require specific siting criteria and are difficult and time-intensive to develop. NorthWestern Energy and its customers **can capitalize on the unique opportunity** to acquire an asset that will have positive cost/benefits to Montana's ratepayers.

Response: NorthWestern will use a competitive solicitation to acquire our customers' resource needs. The solicitation will be open to a broad set of generation technologies, including PHES, and will select resources that are able to meet our customer's needs at lowest long term total cost. Generic PHES system costs were developed by HDR and NorthWestern, and do not necessarily reflect the costs of the Gordon Butte project. NorthWestern plans to use competitive solicitations to acquire resources, as explained in Chapter 13. NorthWestern invites Gordon Butte to participate in its competitive solicitations. Other issues raised by Gordon Butte have been addressed in Chapter 11, or in response to other parties' comments.

ABSAROKA ENERGY LLC

Table of Contents

Table of Figures

Table of Tables

II. Introduction

These comments are offered by GB Energy Park LLC (GBEP), developer of the Gordon Butte Closed Loop Pumped Storage Hydro Project (Gordon Butte PSH), in response to the NorthWestern Energy 2019 Electricity Supply Resource Procurement Plan's (2019 Plan) assessment of the future power supply needs of NorthWestern Energy (NorthWestern). GBEP is a single-purpose subsidiary of Montana-based Absaroka Energy Development Group, LLC (Absaroka).

NorthWestern has offered to electricity consumers and the Montana Public Service Commission (PSC) a plan for an energy resource future, recently filed as the NorthWestern Energy 2019 Electricity Supply Resources Procurement Plan (2019 Plan). The 2019 Plan clearly articulates a future need for additional flexible capacity in the NorthWestern system over the near term. Throughout the Draft 2019 Plan, NorthWestern highlights the importance of new flexible capacity resources[2] to provide the peaking capacity, INC and DEC (ramping), renewable energy integration, and to cover its resource adequacy requirements in order to join the Western Energy Imbalance Market (EIM).[3]

In general, GBEP agrees with this assessment of NorthWestern's future resource needs. As the Pacific Northwest Region shifts away from baseload thermal generation to a mix that will inevitably focus on increasing penetrations of wind and solar, grid operators will need highly flexible, long-lived, fast-ramping platforms that will provide flexible capacity to keep the system reliable, resilient, and affordable.

However, GBEP does not agree with 2019 Plan's conclusion the addition of gas-fired generation is the best and most cost-effective solution for addressing future capacity and flexibility needs.

Throughout the electric utility industry, forward-looking utilities are evolving away from a resource portfolio dominated by conventional generation resources toward more flexible assets,

---

[2] In the 2019 Plan, NorthWestern identifies flexible capacity as: "Resources that can be dispatched on-demand to ramp up and ramp down relatively quickly…Flexible capacity is needed to match generation to short-term variations in load. Additionally, variable energy resources like wind and solar require dispatchable energy resource to balance the energy grid and assure reliability." (2019 Plan 1-4)

[3] In the Western EIM, NWE will have to pass hourly resource adequacy tests to cover its energy trading in the market. By participating in a 15-minute market, fast ramping resources will be highly valuable to the utility. "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."(2019 Plan 5-2)

including energy storage, as a critical component of a least-cost resource mix.[4] Modern, fast responding Pumped Storage Hydro (PSH) is recognized as the most capable, cost-effective, and proven utility-scale energy storage technology in the world.[5] It is also capable of providing the resource needs for capacity, flexibility, ramping and dispatchability that NorthWestern identifies in the 2019 Plan.

GBEP respectfully proposes that Gordon Butte PSH be considered as a robust flexible capacity solution for NorthWestern's system. GBEP believes that, if accurately evaluated, the project will prove to be a **least cost solution and offer a wider range of operational capabilities** than the resources currently proposed in the 2019 Plan.[6]

GBEP acknowledges that under current statute, it is not feasible for the utility to consider both the transmission and generation benefits of large-scale energy storage in the 2019 Plan; however, we feel that it would be highly useful for NorthWestern and its ratepayers to do so. GBEP is willing to work with the utility and the Public Service Commission (PSC) to explore ways that the full value of pumped storage hydro can be demonstrated through a comprehensive analysis of both transmission and generation benefits.

Gordon Butte PSH received an Original Hydropower License by the Federal Energy Regulatory Commission (FERC) in December of 2016, is fully permitted, and has finalized its engineering design. By the time the Draft 2019 Plan is completed, the Project will be construction-ready and will be able to be placed in service in 2024 or soon thereafter. This timeline makes Gordon Butte PSH a viable project that fits neatly into NWE's resource acquisition timeline laid out in their planning document.

New electric resources typically have long life spans (30 years or more) with significant cost considerations for electricity consumers. As NWE evaluates the procurement of new generation into its resource portfolio, a thoughtful, inclusive, and objective review of all options available to NWE will serve to ensure the best resource portfolio to meet NWE's future capacity and flexibility needs. We request that the PSC carefully consider the full range of services and contributions that Gordon Butte PSH offers for Montana's energy future.

---

[4] https://www.greentechmedia.com/articles/read/pacificorps-march-from-coal-toward-clean-energyalternatives?utm_medium=email&utm_source=Daily&utm_campaign=GTMDaily#gs.9cg4sq

[5] http://www.nwhydro.org/wp-content/uploads/events_committees/Docs/2016_Pumped_Storage_Workshop_Presentations/4%20-%20Patrick%20Balducci.pdf

[6] Acelerex. *Gordon Butte Rate Base Analysis.* May 2019. NOTE: Carbon not considered in analysis. CV for Acelerex available in Attachment A

III. Project Overview

Figure 1. Artist rendering of the Gordon Butte PSH Project

GBEP is currently developing the Gordon Butte Closed Loop Pumped Storage Hydro facility in Meagher County. The Gordon Butte PSH project is:

- **CONSTRUCTION READY:** The Gordon Butte PSH has received its 50-year hydropower license from FERC, completed its NEPA environmental review (Environmental Assessment with Finding of No Significant Impact), completed all the necessary permitting, secured the land and water (Montana State issued Water Right), finalized its engineering design, and has engaged the Engineering, Procurement and Construction (EPC) team that will build the project.[7]

- **UTILITY-SCALE:** NorthWestern can contract for the portion of the Project that best fits its needs. The facility has been designed to accommodate multiple operators. Should NorthWestern acquire or contract for a share

[7] The major milestones that have been achieved to date: Land Agreement in Place for Project and Easements, MT State Issued Water Right Permit Obtained, 401 Water Quality Certification Waived – No Water Discharge, NEPA Environmental Assessment – Finding of No Significant Impact, Front End Engineering Design Completed, FERC License Issued (P-13642), FERC License Article Compliance Current, Equipment Selection and Design (General Electric Renewable Energy), Key Subcontractors and Vendors, EPC Team (Ames Construction, Black & Veatch), Interconnect Feasibility and System Impact Studies Completed

of the Project, there are multiple ways that the remaining capacity could be allocated. The facility will have three-unit pairs. Each pair will include a separate pump and turbine, each with a dedicated 134 MW motor and a 134 MW generator, respectively, for an installed capacity of 400 MW with 3,400 MWh hours of storage – or 8.5 hours at continual maximum discharge for 400 MW. Each unit pair will have the capability to be operated independently from one another.

- **FAST-ACTING:** The pump/turbines will be Quaternary units configured in a hydraulic short-circuit (further discussed in Section VI below). This will allow the facility to operate pumps and turbines simultaneously and switch seamlessly from pumping to generating mode. The facility will be able to ramp at an estimated rate of 20+ MW/sec in either direction.[8]

- **FLEXIBLE**: The operational versatility of the units will allow NorthWestern to utilize the facility for flexible capacity, as well as a wide-ranging suite of grid operation services. This suite includes:

  ○ Peaking capacity ○ Energy storage ○ Energy arbitrage
  ○ Integration and firming of existing and future renewables ○ Ancillary services, including

- Regulation Up
- Regulation Down
- Load-following
- Spinning and non-spinning reserves
- Black start
- Voltage Control
- Frequency Control
- System Inertia

[8] The GBEP equipment configuration has earned attention of the hydropower industry and was picked up by the U.S. Department of Energy for the analysis of grid support and economic benefits based on its fast-acting capabilities. https://www.energy.gov/eere/articles/pumped-storage-projects-selected-techno-economic-studies

- INC / DEC

The Gordon Butte facility is equivalent to a Swiss Army knife - able to provide multiple service from a single platform.

IV. Key Conclusions from the NWE 2019 Plan

There are many overarching conclusions from NWE's analysis provided in the 2019 Plan that GBEP agrees with, including the following:

- The 2019 Plan appropriately focuses on the addition of flexible capacity resources. The 2019 Plan identifies a current capacity deficit of **645 MW** and is forecast to grow to **725 MW** by 2025 (1-3).
- NWE is right to focus on the addition of new assets that are capable of meeting the utility's peaking needs.
- NWE is right to take steps to wean itself off of bilateral transactions for its capacity deficits.
- Joining the EIM is a good idea. To participate, NWE will need to demonstrate, on a dayahead basis, the ability to meet its load, ramps, and uncertainty throughout the day. This requirement makes the addition of flexible capacity essential.
- Managing transmission congestion with flexible resources is important and therefore transmission benefits should be taken into consideration in the evaluation of new resources.

While GBEP strongly agrees that NorthWestern will need to acquire additional resources to satisfy their demonstrated needs for capacity and flexibility. The 2019 Plan identifies numerous needs that the advanced pumped storage hydro will be a cost-effective and ideal resource to address (excerpts from the 2019 Plan provided in italics):

- **Peaking resources** – Gordon Butte PSH will be able to provide up to 3,400 MWh of peaking generation in addition to its other ancillary and transmission services. To put this another way, gas peakers can only provide peaking energy, Gordon Butte PSH provides this same service as a part of its "stacked" capabilities.
- "Without new peaking capacity, the market exposure will increase to about 725 MW by 2025 (including reserve margins)." (2019 Plan. Page 1-3)
- **Flexible capacity** – Above and beyond peaking, Gordon Butte PSH will supply a large amount of flexible capacity and provide fast-ramping (20+ MW/sec) operational capability to quickly respond to the minute-to-minute changes in generation and load – keeping the

transmission system in balance. Below are a few of the important future needs and requirements identified in the 2019 Plan:

- "Resources that can be dispatched on-demand to ramp up and ramp down relatively quickly…Flexible capacity is needed to match generation to short-term variations in load. Additionally, variable energy resources like wind and solar require dispatchable energy resource to balance the energy grid and assure reliability." (2019 Plan. Page 1-4)
- "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)." (2019 Plan. Page 3-8)
- "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." (2019 Plan. Page 4-12)
- **Storage for surplus off-peak energy** – Unlike gas-fired resources, energy storage allows grid operators to effectively and efficiently optimize and manage their resources by timeshifting low-cost energy (energy that is currently dumped on the market or curtailed) to times of the day that energy is most valuable.
- "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 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." (2019 Plan, Page 1-5)
- **On-system resource to avoid transmission import risk** – Gordon Butte PSH will interconnect to the Colstrip Transmission System – at a new substation located approximately 5.5 miles south of the Project – the backbone of NorthWestern's system. This location makes it an ideal resource for the utility to optimize both its intra and interstate transmission flows, as well as utilize the fast-acting ancillary services to maintain the reliability and resiliency of its grid.

  "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. The retirement of Colstrip units will impact

NorthWestern Energy's ability to import sufficient power to meet peak energy demands." (2019 Plan, Page 1-9)

- **Gordon Butte PSH can be divided up into capacity slices** – In their draft 2019 Plan, NorthWestern has indicated that they will use a staged multi-year approach to add 200 MW of capacity per year from 2022 to 2025 (2019 Plan. Page 1-13). While the total nameplate capacity of the Gordon Butte PSH is 400 MW, that does not mean that a single offtaker will have to purchase or contract for the entire facility. An offtaker like NorthWestern will be able to purchase and/or contract for the amount of capacity it needs – be it 133 MW, 266 MW, all the way up to 400 MW. In this scenario, GBEP would then offer the remaining capacity to other utility or merchant customers.[9]

As we discuss in detail in Section VII below, advanced PSH is the most mature, cost effective, utility-grade flexible capacity and storage resource available, and should be considered for

[9] The power plant controls have been designed to incorporate GE's Digital Twin software technology. https://www.ge.com/digital/sites/default/files/download_assets/The-Digital-Twin_Compressing-Time-to-Valuefor-Digital-Industrial-Companies.pdf

addressing NWE's capacity needs.[10] The Gordon Butte PSH project has been developed for integration into the regional power system to provide the very capabilities NWE has identified that its system will require in the future.

V. Concerns/Questions with 2019 Plan

Concern: The 2019 Plan results in a huge bet on a single resource type - gas fired generation.

- If resource acquisitions follow what is laid out in the 2019 Plan, approximately 65% of NorthWesterns's peak load contribution will come from gas. (Table 4-1, Page 4-7: peak contributions + 800 MW new gas.)
- NorthWestern's gas transportation system will need to be expanded to accommodate the new facilities. Furthermore, it is understood that the system will be unable to deliver to the new gas units on extreme cold days,[11] as is currently the case at the Dave Gates Generation Station (DGGS), requiring the utility to utilize backup fuel (identified at the DGGS RICE addition as diesel fuel).

  The 2019 Plan includes cost estimates for the additional linear infrastructure needed for RICE additions at DGGS, "…the estimate included $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 of the DGGS facility."(2019 Plan. Page 7-21)

  Question: When analyzing the costs of developing new gas-fired generation assets (other than DGGS) were additional costs for the construction and/or expansion of the natural gas delivery system and transmission system included in the capital cost calculations? If not, what would those costs be?

  Question: Were additional O&M costs assessed for operating the proposed gas plants with diesel and/or alternative fuels? If yes, what specific information was considered?

  Question: The development of new linear facilities (both pipelines and transmission) carry inherent risks, were these considered in the economic evaluations?

---

[10] http://www.nwhydro.org/wp-content/uploads/events_committees/Docs/2016_Pumped_Storage_Workshop_Presentations/4%20-%20Patrick%20Balducci.pdf

[11] *"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."(6-19)*

Concern: It is not clear what type of generating, reliability, shaping, or firming resource NWE energy is seeking.

- There seems to be a focus on meeting peak demands.
- There also seems to be a focus on acquiring more generation to meet reserve requirements, limit exposure to market availability, and be able to meet its own loads while participating in EIM.
- There is also discussion of flexible capacity, with no clear definition of the physical parameters of what is meant by flexible capacity.
- Discussed within the plan is problems with wind and solar not be dispatchable when needed. It is not clear how NWE is going to address integrating, shaping, and scheduling wind and solar to align more with the needs of NWE.

  Question: It is discussed that flexible capacity is tied to meeting INC and DEC needs, how does this differ from the other needs above?

  Question: Is NorthWestern looking for a peaking facility that can be used a limited number of hours per year? Or being dispatched to meet peaking needs?

Concern: The 2019 Plan makes critical assumptions and analytical choices that may favor the all-gas base case.

- The base case includes no carbon cost and the carbon cost sensitivities may not be robust enough to capture the full range of carbon risks.[12] For example, in the past NorthWestern priced in significant carbon risk during the justification of the purchase price for their acquisition of the hydroelectric dams, and then ignored or downplayed carbon risk when acquiring Colstrip 4 and in this 2019 Plan. It appears now that the Montana courts will require this analysis.[13]

  Recently, utility companies throughout the Pacific Northwest are viewing carbon risk, both politically and economically, as a significant factor informing their future resource

[12] "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."(9-12)

[13] Vote Solar, Montana Environmental Information Center and Cypress Creek Renewables, LLC and Windata, LLC vs. The Montana Department of Public Service Regulation, Montana Public Service Commission and NorthWestern Corporation and Montana Consumer Counsel. Order vacating and modifying Montana Public Service Commission Order Nos. 7500c and 7500d. April 2nd, 2019

acquisition decision-making. Table 1 below shows how other Colstrip Utilities are forecasting future carbon pricing in their recent integrated resource plans.

Table 1. Regional Carbon Cost Assumptions

Regional Carbon Cost Assumptions ($/ton)							
	NWE	**NWE High**	**PSE 2017 IRP Mid**	**PGE 2016 IRP Mid**	**PGE 2016 IRP High**	**PacifiCorp 2017 IRP**	**AVISTA 2017 IRP (Colstrip Carbon Cost)**
2018			14.36				
2019			15.37				
2020			16.45				
2021			17.60				
2022			18.82	18.15	22.69		
2023					23.59		
2024			20.14	18.83	24.50		7.00
2025			21.55	19.51	25.41		9.21
2026		**20.00**	23.06	20.19	26.32		11.43
2027		**20.83**			27.22	4.75	
2028		**21.69**	24.67	20.87	31.08	6.25	13.64
2029	**5.71**	**22.59**	26.40	21.55	34.94	8.00	15.86
2030	**7.11**	**23.53**	28.25	22.23	39.02	11.00	18.07
2031	**9.90**	**24.51**	30.23	22.91	42.65	12.50	20.29
2032	**11.44**	**25.53**			46.51		
2033	**13.04**	**26.59**	32.35	23.59	50.36	26.00	22.50
2034	**14.70**	**27.69**	34.62	26.32	54.22	28.00	24.71
2035	**16.42**	**28.84**	37.04	29.04	58.08	29.50	26.93

2036	**17.48**	**30.03**	39.63	31.76	61.93	31.25	29.14
2037	**18.57**	**31.28**	42.40	34.48	65.79	32.00	31.36
2038	**21.22**	**32.58**			69.65		33.57
	22.42	**33.93**	45.37	37.21		37.00	35.79
			48.54	39.93		38.02	38.00
			51.93	42.65			
				45.37			
2039	**23.65**	**35.34**		48.09	73.50		
2040	**24.93**	**36.81**		50.82	77.36		

Question: How should NorthWestern factor in future carbon pricing as they evaluate new resource additions over a 15-year horizon?

Question: In light of the recent District Court ruling in Vote Solar, how will NorthWestern reevaluate future carbon pricing in the final 2019 Plan?[14]

Question: Will current and future laws restricting carbon-based generation in other states affect NorthWestern's ability to utilize gas resources in the EIM? Has this subject been considered by NorthWestern? If so, what inputs were used to address this issue?

Question: Does NorthWestern give any priority to carbon-free assets above and beyond carbon pricing?

Concern: Gas price and carbon price sensitivities are only included for the base case. (Figure 10-3) These sensitivities should be run for all of the resource portfolios in Figure 10-2. This presumably would narrow the gap between the all-gas base case and the other portfolios with non-gas resources.

[14] Vote Solar, Montana Environmental Information Center and Cypress Creek Renewables, LLC and Windata, LLC vs. The Montana Department of Public Service Regulation, Montana Public Service Commission and NorthWestern Corporation and Montana Consumer Counsel. Order vacating and modifying Montana Public Service Commission Order Nos. 7500c and 7500d. April 2nd, 2019

- The 2019 Plan analysis limits surplus energy sales to 10% of annual load.[15] The 10% surplus sales limit may be disadvantaging other resource portfolios relative to the base case. In particular, the Pumped Hydro Portfolio which includes 200 MW of new wind (an assumption that GBEP does not agree with – see below for more detail).

  Question: It's not clear how this criterion is enforced in the model – is it enforced every hour or in aggregate over the year?

  Question: If it's over the entire year, does the model stop making surplus sales after the annual limit is met?

Concern: Sensitivities without the surplus sales constraint should be run for all resource portfolios in Figure 10-2. Doing so would likely narrow the gap between the all-gas base case and the other portfolios with non-gas resources.

Question: NorthWestern seemed unconcerned about making additional surplus sales if they acquired additional shares of Colstrip 4, why treat other potential acquisitions the same?

Concern: NorthWestern's flexible capacity needs may not be adequately represented in the 2019 Plan's hourly PowerSimm modeling.

- The Navigant study that quantifies NorthWestern's flexible capacity needs is described in the 2019 Plan (pages 3-7 to 3-13). The plan also discusses the resources available to meet the flexible capacity needs (see Table 2).[16]

Table 2. 2019 Plan 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%

[15] "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."(10-3)

[16] 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 nad it is therefore rarely economic to call on them for this capability."(4-12)

- During the recent rate case testimony, NorthWestern described in detail the process NorthWestern goes through each hour to determine how much capacity to set aside for potential INC and DEC needs.[17]

- It is not clear the extent to which this hourly decision process is reflected in the PowerSimm modeling that informs the 2019 Plan.[18]

- NorthWestern's hourly strategy for meeting flexible capacity needs should be modeled in PowerSimm so that the true cost of meeting flexible capacity needs with existing and planned resources is accurately portrayed.

  Question: Did NorthWestern model resources at a higher temporal resolution than onehour step sizes?

  Question: How does this model differentiate between fast acting resources like PSH (that can ramp in MW per second) and slower reacting resources like natural gas (that ramp in MW per minute)?

Concern: The ability of the current generation assets to provide the amount of DEC represented in the 2019 Plan.

- In the 2019 Plan, Table 4-1 (page 4-7) lists all of the resources that can potentially be used to provide DEC – this totals more than 800 MW. However, this table overstates the DEC that is usually available for many reasons. The thermal units (200 MW of gas + 100 MW of Colstrip) must be on-line and producing at maximum output to provide the full amount of DEC shown. The renewables (more than 400 MW) must be at full output and NorthWestern must have a contractual right to curtail them to provide the DEC amounts shown. If hydro units are at capacity, NorthWestern would have to be willing to spill valuable no-cost energy to provide DEC.

  Question: What specific operational assumptions were used to analyze the current portfolio's ability to address DEC?

---

[17] Montana Pubic Service Commission. Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules. (Docket No. D2018.2.12. September 28, 2018) Testimony of Joseph M. Stimatz.

[18] "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."(10-1)

Concern: The PSH portfolio may not fully capture the flexible capacity value provided by advanced PSH, especially Gordon Butte PSH.

- Were NorthWestern to acquire a PSH resource like Gordon Butte, the asset would serve as: 1) a low-cost source of flexible capacity; 2) a resource to provide regulation (this would free up capacity in DGGS for other purposes); 3) the primary source of INC and DEC; 4) a minute-to-minute integration and optimization resource for renewable generation; and 5) storage for low cost surplus energy (hydros and baseload thermal generation). It does not appear that the full range of PSH's operational characteristics, flexibility, or stacked value stream were accounted for in the PSH portfolio.

- Ascend Analytics, the company that owns the PowerSimm modeling platform, also owns BatterySimm. This is a modeling platform specifically designed to analyze energy storage technologies.[19]

  Question: Has NorthWestern utilized BatterySimm in their analysis of energy storage, specifically pumped storage hydro? If not, does it plan to?

Concern: NorthWestern's assumptions for how the Pumped Hydro Portfolio was modeled.

- The 2019 Plan modeled conventional (fixed-speed) pumped storage hydro available in 2026.[20] Gordon Butte PSH will use ultra-flexible quaternary technology and be available by 2024.

- Energy storage facilities like Gordon Butte are not energy-only resources. Modeling energy storage takes a sophisticated understanding of the role it plays in a generation and transmission portfolio – the 2019 Plan should reflect this. To create the Pumped Hydro portfolio, NorthWestern added 100 MW of generic pumped hydro storage in 2026. A further 210 MW of additional wind was added to the portfolio because, as noted above, energy storage is not a traditional energy resource.[21] This reasoning is flawed for several reasons:

  - NorthWestern is currently using DGGS, Basin Creek, Colstrip Unit 4, Cochran, Ryan, Mystic, Thompson Falls and other contracted resources to provide for their real power balancing control (RBC). If NorthWestern were to utilize Gordon Butte PSH

---

[19] https://www.ascendanalytics.com/batterysimm.html

[20] This portfolio is based upon the Current portfolio assumptions and adds 100 MW of pumped hydro in 2026. After pumped hydro, additional resources were selected using constrained ARS analysis. (10-11)

[21] "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."(10-16)

for their RBC (a role that advanced PSH is ideally suited to play) then these other gas, hydro and coal assets would be able to be redeployed toward more traditional energy generation. By optimizing the generation fleet in this manner, 210 MW of additional wind would not be needed.

- NorthWestern is currently long at night by an estimated 50+ MW, this amount would likely increase should the utility continue to pursue additional capacity in the Colstrip Generation Station or qualifying facilities (QFs). Instead of selling this energy at off peak hours when prices are low, this long energy could and should be stored for use during the on-peak hours when energy is more valuable.
- Joining the EIM will give NorthWestern access to low-cost regional surplus generation that could be stored in the Gordon Butte PSH and deployed for peaking, ancillary services, or other flexible capacity services.

✦ NorthWestern identified an estimated 55-120 MW of DEC needs in their system.[22] If Gordon Butte PSH were used as a DEC resource, the energy would be stored for use later on – unlike curtailing thermal or renewable generation for this need.

Question: What is the current estimated average amount of long night-time energy? What is the resource composition of that overproduction?

Concern: The transmission benefits of PSH were not included or valued in the modeling.

✦ The value that energy storage assets like Gordon Butte PSH provide to grid operators and their customers is more than just the energy and flexible capacity that were modeled by NorthWestern. The value stack of services includes transmission benefits.

✦ NorthWestern recently filed proposed revisions to its Montana OATT to revise its costbased formulas for Network Integration Transmission Service, Point-To-Point Transmission Service, and certain ancillary services (FERC Docket No. ER19-1756-000).[23][24] This filing points to transmission related issues and needs that Gordon Butte PSH is ideally suited to address – specifically managing increased Variable Energy Resources (VERs) on its system. NorthWestern is increasingly having to recover more costs for Regulation and Frequency Response service for point-to-point exports, and for reserve capacity imposed by due to sudden large decreases of wind generator output. NorthWestern is proposing to increase its recovery rates for Schedule 1 (Scheduling, System Control and Dispatch

[22] NorthWestern Energy's 2019 Plan. Page 3-10

[23] NorthWestern Energy's proposed revisions to its Montana Open Access Transmission Tariff. FERC Docket No. ER19-
[24] -000

Service), Schedule 3 (Regulation and Frequency Response), Schedule 5 (Operating Reserves – Spinning), and Schedule 6 (Operating Reserves – Supplemental) services for VERs interconnecting to its system.

NorthWestern stated the problem clearly:

"When large, sudden down-ramps of wind generation occur on NorthWestern's system, this can have a corresponding deleterious effect in NorthWestern's Area Control Error ("ACE") and place the NorthWestern ACE outside of the Balancing Authority ACE Limit of Standard BAL-001-2. This, in turn may cause NorthWestern to have to deploy flexible capacity in order to maintain compliance with Reliability Standard BAL-001-2 and to maintain system reliability. NorthWestern cannot use Regulation and Frequency Response reserves to address the large sudden down-ramps of wind generation because ***doing so would quickly exhaust NorthWestern's supply of reserves and compromise its ability to meet BA obligations. Similarly, NorthWestern cannot rely upon contingency reserves, which are used for Schedule 5 and 6 ancillary services, to respond to such down-ramps***."[25] (*emphasis added*)

These proposed changes filed at FERC indicate that there is a present and growing need for additional fast-ramping, highly flexible assets in NorthWesterns's portfolio to address its transmission needs as more and more renewable energy generation is interconnected into the grid.

Gordon Butte is designed to provide solutions and services to address this problem, in addition to all of the other valuable services it is able to provide.

Question: The 2019 Plan is focused on additions to NorthWestern's generation portfolio. How does NorthWestern address the proper valuation and considerations for technologies, like energy storage, that can provide value for both the generation and transmission sides of the utility?

Question: Does NorthWestern think that transmission benefits should be accounted for when valuing energy storage – specifically pumped storage hydro?

Concern: The NWE IRP process is not transparent.

[25] NorthWestern Energy's proposed revisions to its Montana Open Access Transmission Tariff. FERC Docket No. ER191756-000. Page 30.

The 2019 Plan discusses the additional interaction with the Energy Technical Advisory Committee (ETAC) during this IRP cycle.[26] While we acknowledge that the establishment of the ETAC is a step in the right direction, we do not believe that it goes far enough. Other utility's planning processes that are transparent and open to participation by all parties (throughout the planning and modeling cycle) are able to access a wider pool of expertise and leverage the process for greater buy-in by the time the draft IRP is made available.

- Many of Absaroka's 2019 Plan questions and concerns could have been considered and addressed during the resource planning process before this draft plan was issued. Instead, NorthWestern is left to defend the 2019 Plan and look at improvements in the next cycle which wastes time and resources.
- NorthWestern appropriately notes that the 2019 Plan is a planning document and that resources will be acquired through subsequent Request for Proposal (RFP) processes.[27] However, NorthWestern also notes that the 2019 Plan models will be used to evaluate RFP resources.[28]
- This is all the more reason to have a transparent and interactive planning process to address any modeling issues and/or key assumptions with this 2019 Plan prior to issuing any RFPs.

VI. Gas vs. PSH

Rate Impact to Customers

GBEP engaged an outside expert (see Attachment A) to conduct detailed modeling and analysis of the rate base impact of the Gordon Butte PSH compared to existing rate-based NorthWestern assets (Colstrip 4, Hydro Dams, Spion Kop, and the DGGS). The results show that, on an equal footing, the advanced pumped storage facility is the lowest cost choice for the utility (see Table 3).[29] Table 4 below shows the Gordon Butte PSH and its total revenue in 133 MW, 266 MW, and 400 MW capacity slices.

---

[26] "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…"(2-9)

[27] NorthWestern Energy, 2019 Plan. Page 1-14

[28] 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.(10-25)

[29] Acelerex. Gordon Butte Rate Base Analysis. May 2019. CV for Acelerex available in Attachment A

Table 3. Comparison of existing rate-based assets versus Gordon Butte PSH.

Item	DGGS	SPION	Colstrip	Hydro	Gordon Butte
Total Revenue	$29,244,149.00	$11,683,771.0	$77,680,104.00	$142,759,244.00	$72,488,341.54
Capacity [MW]	150	40	222	448	400
Revenue $/kW-yr	$194.96	$292.09	$349.91	$318.66	$181.22

Table 4. Gordon Butte total revenue requirement by portion of facility.

Item	Gordon Butte 133 MW	Gordon Butte 266 MW	Gordon Butte 400 MW
Total Revenue	$24,102,373.56	$48,204,747.12	$72,488,341.54
Capacity [MW]	133	266	400
Revenue $/kW-yr	$181.22	$181.22	$181.22

The valuation of the cost of service was produced by a Production Cost model (developed by Acelerex). Acelerex, through key staff, are prepared to discuss these results with the utility, its consultants, the commission, and staff upon request.

Lifecycle Costs

The 2019 Plan has identified that NorthWestern will require 725 MW of new capacity, particularly flexible capacity, additions by 2025 (including reserve margins).[30] While these future flexibility needs could conceivably be met by more flexible gas units (as identified in the 2019 Plan), such as aeroderivative combustion turbines (CTs) or reciprocating engines, energy storage technologies can perform these duties much more economically because of their two-way capability – full output to full storage – effectively doubles their flexible operating range compared to nameplate capacity. For example, Gordon Butte is able to generate at 400 MW (+100%) and store energy through pumping at 400 MW (-100%) giving it a flexible operating range of 800 MW. This is in contrast to a gas-fired unit that must be up and operating at a given set-point in order to be then run up or down.

Simply put, an energy storage facility is able to be operated for flexible capacity at 200% of its nameplate, while a gas unit can only offer some fraction of its overall nameplate for the same service (see Figure 2 below).

[30] NorthWestern Energy, 2019 Plan. Page 1-3

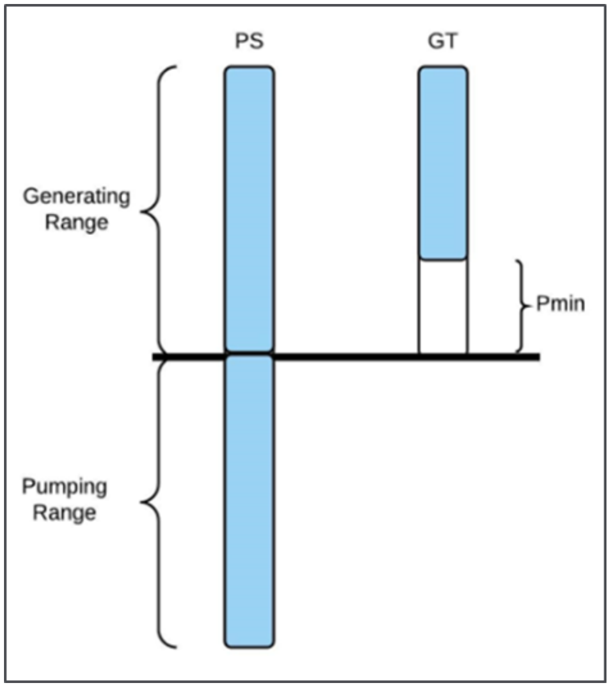


Figure 2. PSH operational range versus gas.

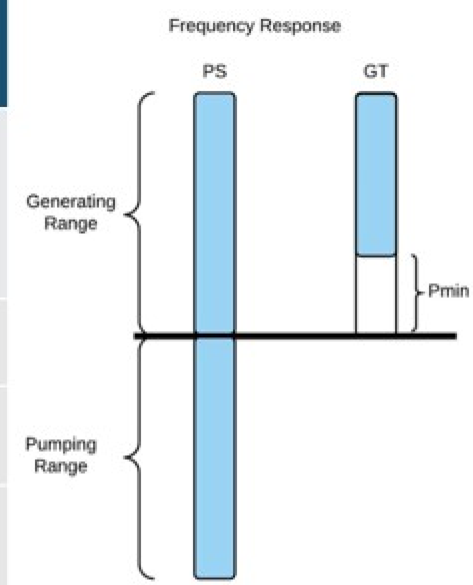
Absaroka Energy commissioned E3 Consulting to compare quaternary pumped storage hydro technology against gas peakers (aeroderivative CTs, reciprocating engines and frame CTs) for various flexible capacity products on a levelized cost per kW basis. The cost numbers used for the gas-fired units were derived from NorthWestern's 2019 Plan. Cost numbers for the quaternary PSH facility are based on GBEP's most up-to-date cost estimate figures for the Gordon Butte PSH.

The results of this study are provided as Attachment B and demonstrate that **pumped storage hydro provides these flexible capacity products at a significantly lower cost**. Some of the results of this analysis are provided below.

Flexible Capacity: Frequency Response

- Primary control - most immediate response to deviations in grid frequency
- Served by generator inertia
- Provided primarily by frequency responsive loads and synchronous generators

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Inertia of turbine and generator provides frequency response • Some markets offer fast-frequency regulation products	200%	$1,220
ICE	• Primary response requirement for generators with governor function may exist • WECC specifies droop settings for conventional generators	79%	$2,320
Aero		47%	$2,843
Frame		87%	$1,647

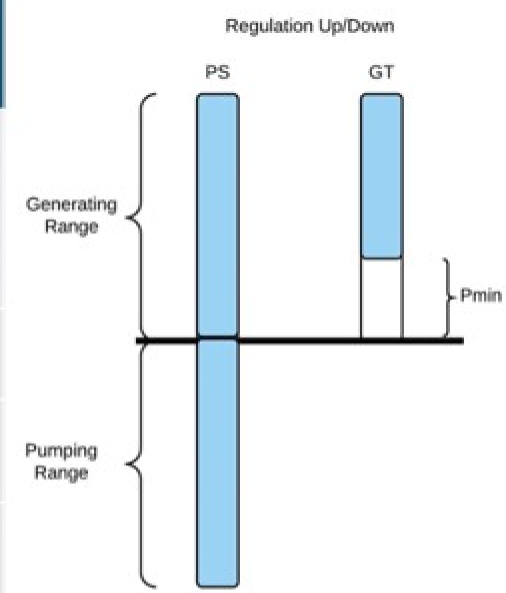


*Assuming operating state is at optimal position for providing frequency response [ex. GT at Pmin]

Flexible Capacity: Regulation Up/Down

- Secondary control - occurs within seconds to minutes via automatic generation control
- Provided by generators who are online and have capacity to increase or decrease output

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Capacity to increase/decrease system output by reducing/increasing generation or load • Fast switching between modes doubles the effective range unit.	200%	$1,220
ICE	Capacity of conventional generators to provide regulation up and down is limited by ramp rate and minimum power generation levels.	79%	$2,320
Aero		47%	$2,843
Frame†		87%	$1,647



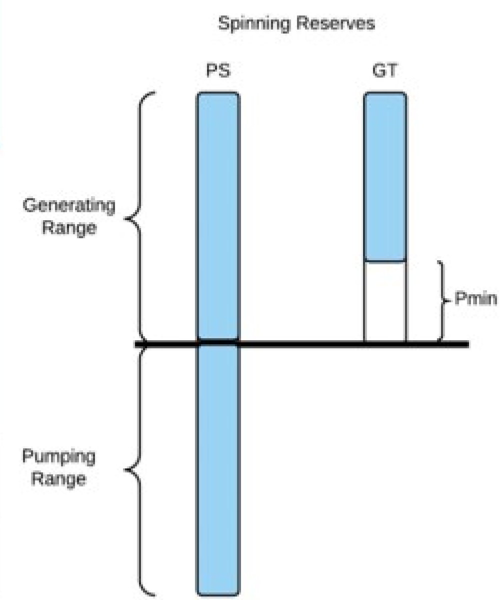
*Assuming operating state is at optimal position for providing frequency response [ex. GT at Pmin]

†Frame units are not usually used for Regulation given their limited operating flexibility

Flexible Capacity: Spinning Reserves

- Tertiary control - system operator dispatches reserves in response to contingencies
- Provided by units that are synchronized to the grid and able to ramp up within specified time frame

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Fast ramp rate and mode switching allows for fast response to operator dispatch • Unit in generation, idling, or pumping mode • Can increase/decrease load or generation • Can switch from one mode to another	200%	$1,220
ICE	• Limited by ramp rate, start-up times (hot-start)	79%	$2,320
Aero		47%	$2,843
Frame		87%	$1,647



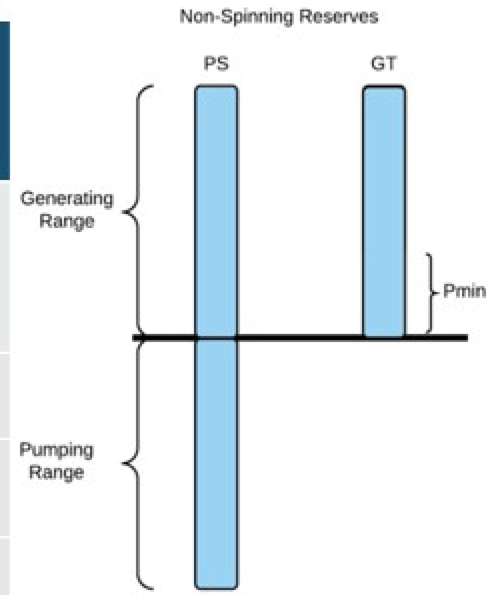
*Assuming operating state is at optimal position for providing frequency response [ex. PS pumping, GT at Pmin]

Energy+Environmental Economics

Flexible Capacity: Non-Spinning Reserves

- Tertiary control - system operator dispatches reserves in response to contingencies
- Provided by units that *are not necessarily* synchronized to the grid, but able to ramp up generation within specified time frame
- Required response time is slower than spinning reserves

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Unit in standby mode • If dispatched, can quickly ramp up capacity	200%	$1,220
ICE	• Capacity and participation limited by ramp rate, start up time (cold-start)	100%	$1,833
Aero		100%	$1,336
Frame		100%	$1,433



**Assuming operating state is at optimal position for providing frequency response (ex. PS pumping, GT not on)*

Additionally, gas-fired resources have minimum run times and minimum operating set-points that need to be accommodated when utilized for the minute-to-minute duties of balancing load and generation in the grid (see Figure 3 below). This includes fuel use and operational wear and tear from multiple daily cycling.

Assumptions

		Quaternary Pumped Storage	Natural Gas Simple Cycle†		
Operating Characteristic	Units	Pumped Storage Hydro (PSH)*	Internal Combustion Engine (ICE)	Aeroderivative Combustion Turbine (Aero)	Frame Combustion Turbine (Frame)
Min Run Time	Hours	not reported	1	8	8
Min Down Time	Hours	not reported	1	7	7
Operating Range	[min –max, as % of capacity]	-100% (pumping) – +100% (generating)	21%-100%	53%-100%	13%-100%

Figure 3. Minimum run time, minimum down time, and operating range for flexible resources.

Regulation at Night – Regulation During Day

In addition to having different impacts on overall portfolio capital costs, flexible gas-fired units and PSH will perform differently in system operations. Utility resource planning processes frequently rely upon hourly production cost modeling with some nominal amount of capacity set aside as a proxy for short-term regulation and balancing requirements. This approach may be sufficient for typical resource planning studies, but it is inadequate for accurately evaluating different flexible capacity resources.

To properly evaluate different flexible capacity options, it is necessary to perform detailed modeling that accounts for variations in performance for competing technologies. The following general examples are given to illustrate the differential in operational capabilities under various system conditions:

<u>Example 1 – Morning Load Pickup Hour</u>

Consider a load pickup hour in the morning where load is expected to increase by 150 MW over the course of the hour.

- This load ramp could be met by 150 MW of RICE (ignoring minimum load requirements) ramping from 0 to 150 MW. Assuming a uniform load ramp, the ICE units will produce 75

MWh during this hour.[31] This generation will likely be out-of-market given the heat rate for RICE units.

- Alternatively, this 150 MW load ramp could also be met 75 MW of PSH ramping from 75 MW pumping to 75 MW generating. The PSH would produce no net out-of-market energy over this hour.

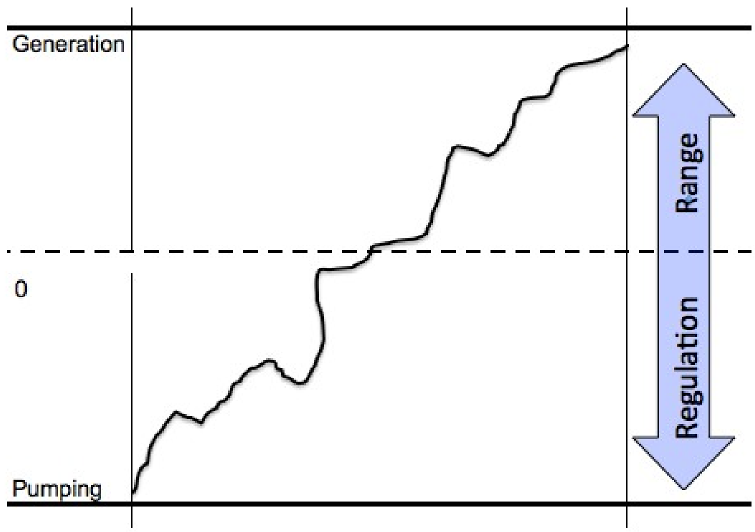


Figure 4. PSH Load Regulation – Morning Load Ramp

Example 2 – Nighttime Load Hour

Consider a nighttime hour when load is expected to be relatively steady and assume that the system operator needs 25 MW of regulation up and 25 MW of regulation down to deal with load variability and uncertainty.

- This need could be met by running RICE units at an expected level of 25 MW (again ignoring minimum load requirements) to leave room to regulate down if the load does drop off. The expected generation from the RICE units would be 25 MWh (plus any minimum load requirement). Again, this generation will likely be out-of-market, especially during nighttime hours, given the heat rate for RICE units.

- This same need could be met by 75 MW of PSH operating at an expected level of 50 MW pumping to leave room for additional pumping if the load does drop off. Instead of

[31] These suggested numbers are for demonstration only. We would appreciate the opportunity to properly analyze these issues with data from actual operations.

producing out-of-market energy, the PSH would be expected to store 50 MWh of energy that would be available at attractive prices during nighttime hours.[32]

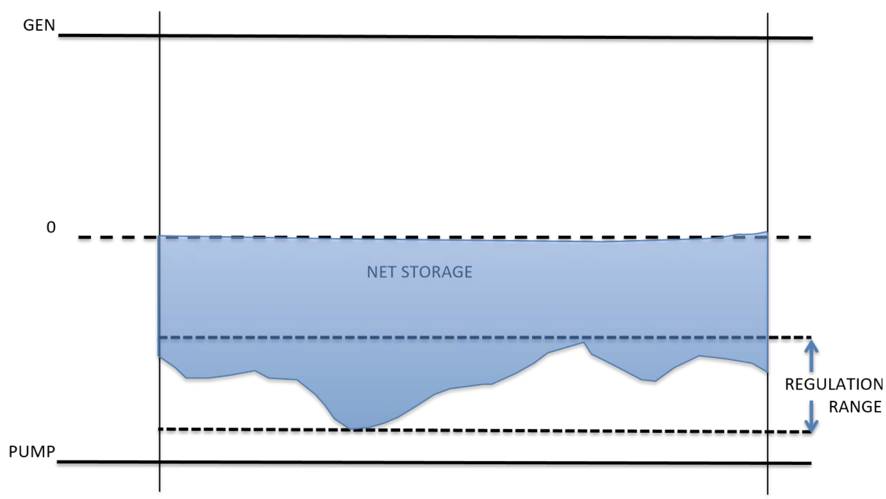


Figure 5. PSH Load Regulation – Typical Nighttime Hour

Example 3 – High Wind Hour

Consider an hour when NWE's wind fleet is operating at maximum output resulting in a need for 150 MW of regulation up in case the wind drops off.

- This need could be met by 150 MW of RICE on-line and ready to ramp up if the wind does fall off.
- The same need could be met by 75 MW of PSH set to 75 MW pumping and ready to ramp up to 75 MW generation if the wind does fall off. If the wind does not fall off, the PSH would store 75 MWh of wind energy that would likely be in excess of NWE's needs.

[32] The hydro fleet recently reacquired by NWE is primarily a run-of-river hydro and therefore cannot be turned down in off-peak hours. During nighttime hours, NWE's portfolio is long by approximately 50 MW. This energy could be utilized by the Gordon Butte PSH to regulate in pumping mode at night.

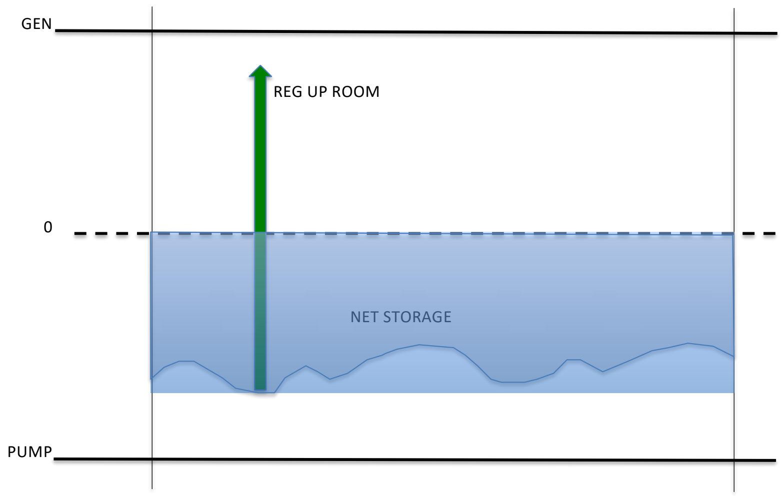


Figure 6. PSH Wind Regulation –High Wind Hour

These examples demonstrate that the operational impacts of RICE (or other flexible gas units) and PSH are different and should be treated as such. To quantify this difference, we feel it is essential to conduct detailed production cost modeling that is sensitive to how ancillary service needs vary under a full range of system conditions.

Natural Gas, The Next Stranded Asset

A recent report by the Rocky Mountain Institute, highlights some of the risks associated by the current efforts to build out the natural gas generation fleet.[32] The current fleet of thermal power plants is aging, with over half of this fleet being more than 30 years old and expected to reach retirement age by 2030. Currently, technology advances and low natural gas prices have led to a rush to gas; utilities and independent power plant developers announcing plans to invest over $110 billion in new gas-fired power plants along with $32 billion in proposed gas delivery infrastructure through 2025.[33]

However, natural gas power plants are not the only generation assets capable of replacing the retiring thermal fleet. Renewable energy generation, such as wind and solar, prices have fallen precipitously in price over the past 10 years, and new fast-acting pumped storage hydro technologies have emerged that can offer firm, dispatchable energy products that provide the same service as the coal plants, often at a net cost saving.

The price of these "clean energy portfolios" (VER + Storage) are expected to continue to decline over the next decade. RMI's analysis revealed that across a wide range of their case studies, regionally specific clean energy portfolios already are outcompeting proposed gas-fired generators, and/or threaten to erode their revenue within the next 10 years. The investments made in gas power plants in addition to the additional investments needed in the gas delivery system **are already at risk of becoming stranded assets**.

In addition, natural gas fuel prices, while currently at low levels, will likely go up and become increasingly volatile. Natural gas prices are a function of supply and demand and subject to volatility based on stockpile levels, infrastructure conditions and weather.[34]

NorthWestern and Montana's Public Service Commission should avoid the risk of locking in significant ratepayer costs for new gas-fired resources that are increasingly uneconomic, and carefully consider alternatives to new gas generation before allowing recovery of costs in rates.

[32] M. Dyson, J. Farbes, and A Engel. The Economics of Clean Energy Portfolios: How Renewable and Distributed Energy Resources Are Outcompeting and Can Strand Investment in Natural Gas-Fired Generation. Rocky Mountain Institute, 2018. www.rmi.org/insights/reports/economics-clean-energy-portfolios

[33] M. Dyson, et. al. Page 10

[34] https://www.eia.gov/energyexplained/index.php?page=natural_gas_factors_affecting_prices

https://www.cnbc.com/2019/01/14/natural-gas-prices-spike-13-percent-on-forecasts-for-long-severe-cold.html

More information on this may be found at: www.rmi.org/insights/reports/economics-cleanenergy-portfolios.

Fuel Supply

New gas fired resources will need costly upgrades to the gas delivery system that, outside of the RICE additions at DGGS,[33] appear to be unquantified in the 2019 Plan. This fuel supply is subject to volatility in the markets, disruptions from gas line failures (as Puget Sound Energy recently experienced),[34] exposure to future carbon pricing risk in the future (see Section III above). To account for these risks, NorthWestern has proposed that on-site alternative fuel such as diesel will be available to make up for shortcomings in the months when natural gas is unavailable or prioritized for uses like home heating on cold days above the generation of energy.

In contrast, the Gordon Butte PSH will draw from the regional grid via the Project's interconnection to the Colstrip Transmission System for its "fuel supply." This supply will therefore be whatever the least cost energy from the grid is available at any given time from the multiple interconnected energy generation sources (wind, coal, gas, hydro, solar, etc.) to

[33] RICE Additions

[34] https://www.seattletimes.com/seattle-news/puget-sound-energy-asks-customers-to-conserve-power-aftercanadian-natural-gas-pipeline-ruptures/

recharge the upper reservoir. This fuel supply is sensitive to regional electricity markets. As we look to the future, we see that generation sources such as regional wind energy generation, solar production on the West Coast and springtime Columbia River hydropower continue to be in oversupply, depressing regional energy prices – and this trend will only increase over time. These downward pricing trends will be captured by the Gordon Butte PSH, driving down fuel supply costs for the facility.

There will be an estimated 15% efficiency loss between the generation and pumping energy. However, this round-trip efficiency penalty is more than offset by out-of-market energy costs incurred when operating other technologies such as gas-fired units for regulation and load following.

Because of the diversity of generation sources in the grid fuel supply for the Gordon Butte PSH carries no risk of disruption and minimal price volatility to supply flexible capacity and ancillary services for NorthWestern.

Case Study – Looking at Wind and PSH in NWE's System

GBEP has investigated the ability of advanced PSH to be paired with VERs to provide firmed, dispatchable on peak energy.

To visualize and understand the behavior and value of PSH technology, GBEP developed a basic modeling system to simulate the operation and effects of a pumped storage system paired with generation from renewable resources. The model allows the user to enter 10-minute production data and specify the physical parameters (size, duration, efficiency, etc.) of the storage facility as well as provide operational instructions (target output levels, pumping/generating preferences, etc.) and market conditions (peak hours, excess power availability, etc.) to influence and finetune the "decision-making" of the pumped storage facility.

Using this tool, GBEP evaluated the interaction of a 1/3 portion of the Gordon Butte Pumped Storage facility (134 MW turbine and 134 MW pump unit) paired with a single 230 MW wind farm located in central Montana. Actual 10-minute wind data was used to run the model. For off-peak energy storage, the simulated storage facility was allowed to make use of the utility's "long" resources at night (up to 75 MW)[35] in addition to the energy produced by the 230 MW wind farm. GBEP then instructed the program to calculate capacity factors during peak hours. The table below compares the average hourly generation and capacity factors of the wind farm alone to those of the combined wind+PSH system.

Table 5. Results of wind and PSH on-peak capacity factor modeling.

[35] The model assumes 75 MWs of "long" opportunity at night based on public statements by NorthWestern; it is anticipated that this number will grow in the future as more wind is interconnected in Montana.

Hour:	Wind Production (GWh):	Wind Capacity Factor (%):	Wind+PSH Production (GWh):	Wind+PSH Capacity Factor (%):
8	34.11	40.63%	68.32	81.38%
9	35.46	42.24%	68.83	81.99%
10	37.76	44.97%	69.93	83.30%
11	39.62	47.19%	71.08	84.67%
12	41.21	49.08%	70.79	84.32%
13	41.43	49.35%	64.20	76.48%
14	42.18	50.25%	61.09	72.77%
15	41.55	49.50%	57.81	68.86%
16	40.83	48.63%	54.90	65.40%
17	40.27	47.97%	53.25	63.44%
18	38.87	46.30%	50.85	60.57%
19	36.82	43.86%	48.41	57.67%
20	34.73	41.36%	44.81	53.38%
21	32.59	38.82%	41.56	49.51%
ON-PEAK AVERAGES	**38.39**	**45.73%**	**58.99**	**70.27%**

These results clearly show the value that PSH will add to renewables and NWE's system; demonstrated by the significant boost that a pumped storage system provides during critical peak hours. This, in effect, creates a dispatchable and completely renewable generation resource.

For comparison, the capacity factors of the real-world utilization of other types of generation resources are as follows:

- Coal: 56.15% (6-year average)
- Natural Gas - Combined Cycle: 52.8% (6-year average)
- Natural Gas – Peaker: 7.3% (6-year average)[36]

[36] https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a

- Traditional Hydro: 42.08% (11-year average)[37]

What is not shown in the model is using the allocated share of Gordon Butte to not only shape and dispatch the wind, but to also provide regulation duty at the same time.[38] To assess this opportunity we would bias the model to use the PSH to regulate on the pump side at night and switch to regulating on the generation side during the day. This would likely reduce slightly the on-peak capacity output of the wind as the PSH units moved up and down in regulation mode, but at a starting point of an on-peak capacity factor of 70%, the diminution will likely not invalidate the point. GBEP would like the opportunity to work with the utility to better model the PSH facility and its interactions with VER to quantify the cost/benefit opportunities of using a slice of the PSH for NWE's system. GBEP is confident that the results would be substantial.

Additionally, it is important to note that the model is limited in its ability to fully quantify the benefits that will be provided by a pumped storage facility.[39] GBEP would welcome the opportunity to work directly with NorthWestern to more holistically model the Gordon Butte PSH in their system to see how the facility is able to provide value to NWE's system, and at the same time, solve the issues identified in the 2019 Plan.

VII. Gordon Butte PSH

Technology Overview - Quaternary

PSH accounts 95% of the current existing energy storage asset in the United States. There are 40 currently operational PSH facilities that provide an estimated 25 GW of storage. However, the fleet of domestic PSH facilities are not responsive enough to currently compete against other flexible capacity technologies, such as fast-ramping gas units and batteries. These PSH plants were largely built in the 1970's and 1980's and were paired with large thermal generators such as coal and nuclear. The equipment used was conventional fixed-speed pump/turbine units. Over

---

[37] https://www.energy.gov/sites/prod/files/2018/04/f51/Hydropower%20Market%20Report.pdf

[38] This potential configuration was discussed with David Gates while at the utility and before his unfortunate death – that Gordon Butte could provide regulation services and allow, once Gordon Butte was on-line, what was then the Mill Creek project to evolve to a peaker or combined cycle facility; in fact, Gordon Butte could provide this resource for less money than ratepayers are charged for DGGS; again this does not take into account the other opportunities and risk mitigation benefits illustrated in part in the Case Study

[39] For instance, the simulation developed by GBEP relies on a relatively small amount of input data (wind farm production, target values, and facility parameters) and does not accommodate additional data such as forecasted weather or transmission system data or variations in daily load patterns. The model also does not account for the PSH's ability to perform other services such as regulation and ancillary services and does not account for any regional resource diversity.

the past two decades, a new class of PSH equipment has been developed and successfully deployed throughout Europe, Asia, and around the world.

The quaternary technology that the Gordon Butte facility will utilize is the fastest responding pumped hydro technology available today for grid services.[40] This configuration will consist of separate pumps and turbines, each with a dedicated 134 MW motor and 134 MW generator, respectively. The equipment will also be connected in a hydraulic short circuit - basically a hydraulic loop connecting the turbine and the pump utilizing the lower reservoir. This equipment configuration will allow the facility to both pump and generate at the same time and seamlessly switch from pumping to generating and back again (including cold-start) at an estimated 20+ MW/sec.

The quaternary equipment configuration will preserve the basic components of the Project's previous ternary configuration; the turbine and pump will be separated, the ability to operate independently of one another, and the hydraulic short circuit. The quaternary PSH also improves upon the mode-switching speeds, start and shutdown times, and the +/- 100% operational range of the facility – all for a lower unit cost.

Figure 7 below is a 24-hour operational profile of a single unit at the KOPS II Pumped Storage Hydro Facility in Austria. This facility has developed equipment with a similar operation range and capability as the Quaternary configuration planned for Gordon Butte PSH. KOPS II has 3 equally-sized units with an installed capacity of 175 MW of generation and 150 MW of pumping. This figure shows the rapid intra-hour mode changes from pumping to generating, as these Ternary units "absorb" load and generation fluctuations on the grid, keeping it stable and operational. The plant is able to move very quickly in either direction. This mirrors the intermittent behavior of variable energy generation profiles, particularly the wind.

[40] Z. Dong, J. Tan, E. Muljadi, R. Nelms, M. Jacobson. "Modeling of Quaternary Pumped Storage Hydropower (Q-PSH) for Power Systems Studies" *IEEE Transactions on Energy Conversion*. 2019

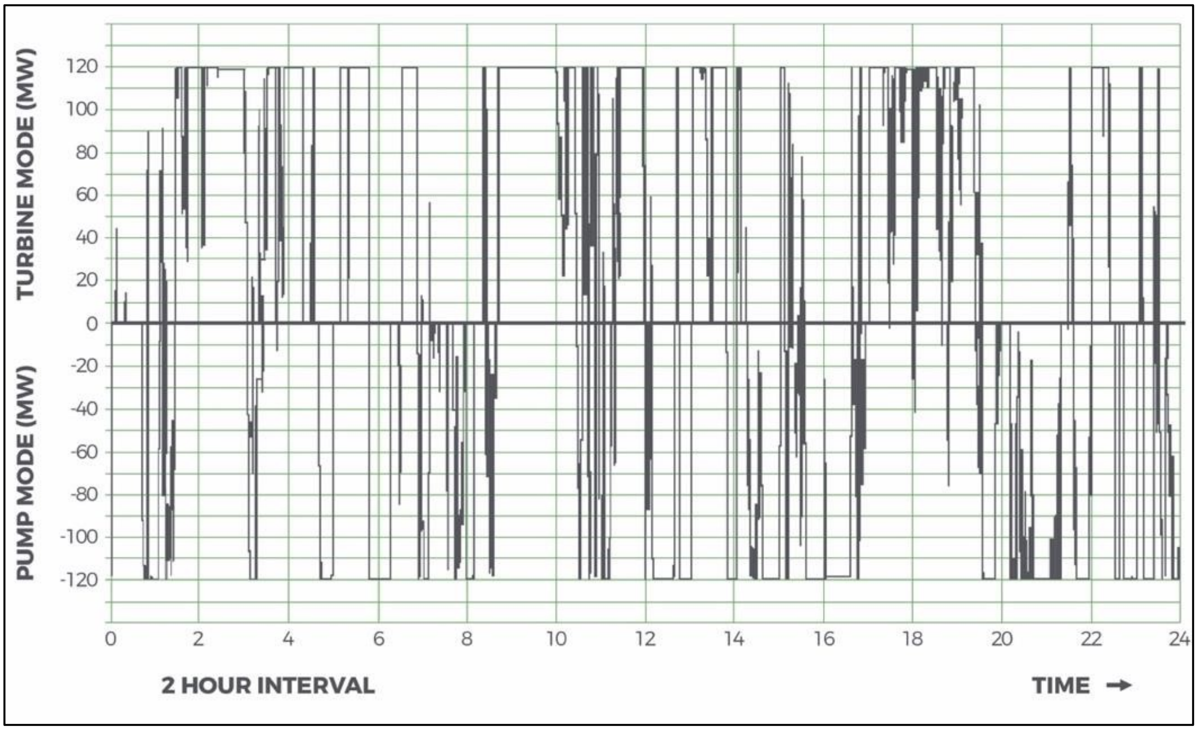


Figure 7. 24-hour operational profile of a single unit at Kops II

Quaternary PSH can provide higher storage capacity with minimal maintenance over a 50+ year lifetime. Older conventional pumped storage plants could only operate in either generating mode or pumping mode. The transition between these two modes would require the unit to come to a full stop, dewater the unit, then restart it in the opposite direction. The fast response time and operational range of the modern quaternary units are a result of their ability to operate both the pump-motor and the turbine-generator simultaneously.

This feature enables Quaternary to provide fast acting response to power system operational changes that are important to system reliability.

At 400 MW of nameplate capacity, Gordon Butte PSH will be able to offer 800 MW of fast acting regulation capacity (the ability to generate 400 MW and pump 400 MW) and switch from pumping to generating and back again at approximately 20+ MW/sec. Again, the utility is able to acquire or contract for all or a portion of the facility's capacity.

The speed at which modern quaternary units can operate makes the Gordon Butte PSH a large and robust rechargeable "battery" that is able to provide storage over different intervals of time including: hourly (energy arbitrage, renewable integration, ramping, peaking / peak shaving), sub-hourly for ancillary services, and fast acting (frequency control, regulation and essential reliability services).[41]

VIII. Energy Storage Projects Not Fitting Well into Utility Resource Planning

In October of 2017, the Washington UTC issued the *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition.*[42] GBEP believes that this report correctly identifies and clearly articulated the historic problems of evaluating energy storage, particularly utility-scale projects such as the Gordon Butte PSH, through the traditional utility planning process. The reality is that large, capital-intensive projects provide value and benefit that is spread across the generation, transmission and distribution networks of a utility company, and offer products that not properly accounted for during the planning and acquisition processes.

The Washington UTC succinctly summed up the issue: "Historically, utility resource planning has taken place within the independent silos of generation, transmission, and distribution. Energy storage can act in any one of those functions, but the challenging corollary is that to generate sufficient benefits to offset its cost, it will most likely be required to act in more than one function. In a planning regime that narrowly looks at the functions separately, energy storage is unlikely to appear cost effective through the lens of any single function, which appears to be one likely reason that past IRPs have not determined energy storage technologies should be included in a utility's resource mix."

GBEP endorses the following guidelines outlined in the October 2017 Washington UTC report and encourages NorthWestern to ensure that energy storage is properly evaluated during the anticipated upcoming Request for Proposals in 2019 and beyond.

- The many value streams provided by energy storage should be stacked to provide a holistic representation of benefits.
- Energy storage should be credited for benefits across generation, transmission and distribution sides of the utility's network.

[41] https://gordonbuttepumpedstorage.com/project-overview/project-video/
[42] Washington Utilities and Transportation Commission, Modeling Energy Storage: Challenges and Opportunities for
Washington Utilities, May 2015. https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=U-151069

- Energy storage should be modeled on a sub-hourly basis to better capture the operational benefits of instantaneously available bulk energy storage.
- NorthWestern should allow stakeholders access to their modeling assumptions and results and recommend alternative scenario recommendations, if warranted.
- NorthWestern and the Montana PSC should consider alternative procurement strategies for large energy storage facilities that are not properly valued in a traditional utility procurement process.

Attachment A

Acelerex Key Personnel

Randell Johnson, PE PhD

PRESIDENT & CEO
ACELEREX

Dr. Randell Johnson's PE career spans 25 years across 70 countries to deliver grid optimizations, power and energy market risk analysis, M&A guidance, as well as planning and strategy for utilities, developers, investors, and governments. Altogether, the energy infrastructure projects Dr. Johnson has advised are valued at a cumulative $35 billion. Furthermore, Dr. Johnson led modelling efforts for the ground-breaking *Massachusetts State of Charge Report* and spearheaded analytics for *NYSERDA Energy Storage Road Map*, in addition to contributing to several other major energy storage studies which have not yet become public.

Dr. Johnson currently leads Acelerex as President and CEO. Acelerex is an independent consulting and software firm providing data analytics services with specialties in energy storage and grid studies. Acelerex provides these services for a range of clients including utilities, governments, grid operators, regulatory commissions, developers, equipment makers and others. Headquartered at the Cambridge Innovation Center (CIC) in Boston, Acelerex also has a Houston office.

Dr. Johnson earned both his PhD and Masters of Engineering from Rensselaer Polytechnic Institute (RPI) in Upstate New York, receieved his Masters of Science in Quantitative Finance from Cass Business School in London, and specialized in Gas and Electric Utility Corporate Finance at UConn School of Business.

Attachment B

E3 Analysis *Quaternary Pumped Storage Flexible Capacity Assessment*

Energy+Environmental Economics

Quaternary Pumped Storage Flexible Capacity Assessment

Prepared for Absaroka Energy in response to NorthWestern Energy's 2019 Electricity Supply Resource Procurement Plan

4/29/2019

Arne Olson, Partner
Doug Allen, Managing Consultant
Vivian Li, Associate

Analysis Description

- **Absaroka Energy LLC asked E3 to compare their quaternary pumped storage technology to conventional resources in terms of their ability to provide "flexible capacity"**
  - Conventional resources considered: Internal Combustion (Reciprocating) Engine, Frame Combustion Turbine, Aeroderivative Combustion Turbine
- **Flexible capacity does not have a specific definition, so we have looked at each resource's ability to provide**
  - System capacity

- Ancillary Services

Flexible Capacity Cost Comparison

Nameplate Capacity	Frequency Response	Regulation Up/Down	Spinning Reserves	Non-spinning Reserves
Ability to provide capacity during peak events and contribute to required reserve margins	Most immediate response to deviations in grid frequency served by generator inertia	Provided by generators that are online and have capacity to increase or decrease generation output or load consumption (pumping)	Provided by units that are synchronized to the grid and, upon dispatch, able to ramp up within specified time frame	Provided by units that need not be synchronized to the grid, but are able to ramp up generation within specified time frame upon dispatch

Capital Cost Analysis

$$\text{Product Speci,ic Cost}\left(\frac{\$}{\text{kW}}\right) = \frac{\text{Capital Costs}^{*}\ (\frac{\$}{\text{kW}})}{\text{Product Speci,ic Usable Capacity (\%)}}$$

** Capital costs considered in this analysis include infrastructure costs as detailed in the 2015 NWE Electricity Supply Resource Procurement Plan*

Cost Comparison

- **For each capacity product, we describe the ability of the different generating technologies to supply that product**
- **We then calculate the product-specific cost per kW by technology**
  - Allows for more balanced comparison of "capacity cost" than a simple $/kW installed cost
- **This comparison focuses on *costs per unit of flexible capacity only*, and does not include an analysis of potential revenues**

Comparison Scope

- **This analysis looks solely at the comparative capital costs (per installed kW) of the different technologies**
  - Accounts for each technology's ability to provide different capacity services
  - Does not account for
    - Fuel / Variable Operating costs
    - Revenues from participation in energy markets
    - Potential impacts of carbon price or air quality operating restrictions
    - Carbon benefits of absorbing renewable overgeneration for later use

Assumptions

		Quaternary Pumped Storage	Natural Gas Simple Cycle†		
Operating Characteristic	Units	Pumped Storage Hydro (PSH)*	Internal Combustion Engine (ICE)	Aeroderivative Combustion Turbine (Aero)	Frame Combustion Turbine (Frame)
Technology	-	Ternary Unit	Warsila 18V50SG	GE LMS100	GE 7EA
Capacity	MW	150	18	50	50
Capital Costs◊	2018$/kW	$2,439	$1,833	$1,336	$1,433
Ramp Rate	MW/min	300	4	10	4
Start Time	min	0.4 – 1.5	not reported	not reported	not reported
Shut-down Time	min	2Δ	not reported	not reported	not reported
Min Run Time	Hours	not reported	1	8	8
Min Down Time	Hours	not reported	1	7	7
Operating Range	[min –max, as % of capacity]	-100% (pumping) – +100% (generating)	21%-100%	53%-100%	13%-100%

* *Data provided by Absaroka*

† *All Data taken from New Resources Cost Summary for Western MT section of the NorthWestern Energy 2019 Electricity Supply Resource Procurement Plan*

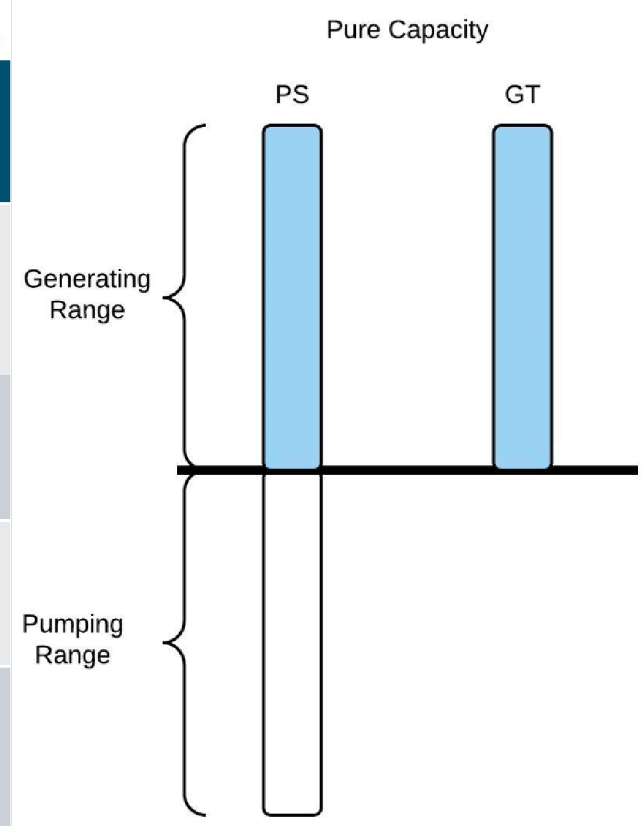
Δ *Assuming "transfer mode" as the final state of rest*

◊ *Includes "Infrastructure" costs as described in NWE's Procurement Plan*

Nameplate Capacity

- Usable capacity provided by the unit (as listed in the NWE Electricity Supply Resource Procurement Plan)
- Reflects the unit's contribution to reserve margins / system capacity
- Amount of capacity available to meet peak capacity needs

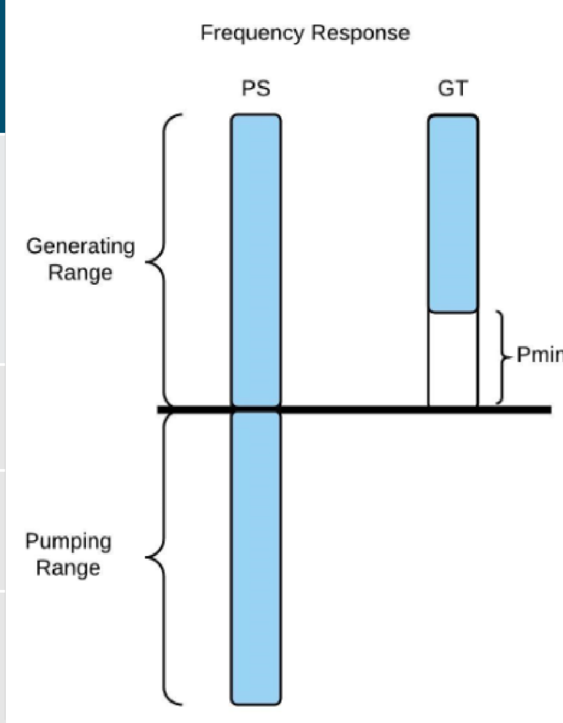
	Capacity Assumptions	Capital Costs (2018 $/kW)
PSH	Generation rated power = 150 MW Pumping rated load = 150 MW	$2,439
ICE	Generation rated power = 18 MW	$1,833
Aero	Generation rated power = 50 MW	$1,336
Frame	Generation rated power = 50 MW	$1,433



Flexible Capacity: Frequency Response

- Primary control - most immediate response to deviations in grid frequency
- Served by generator inertia
- Provided primarily by frequency responsive loads and synchronous generators

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Inertia of turbine and generator provides frequency response • Some markets offer fast-frequency regulation products	200%	$1,220
ICE	• Primary response requirement for generators with governor function may exist • WECC specifies droop settings for conventional generators	79%	$2,320
Aero		47%	$2,843
Frame		87%	$1,647

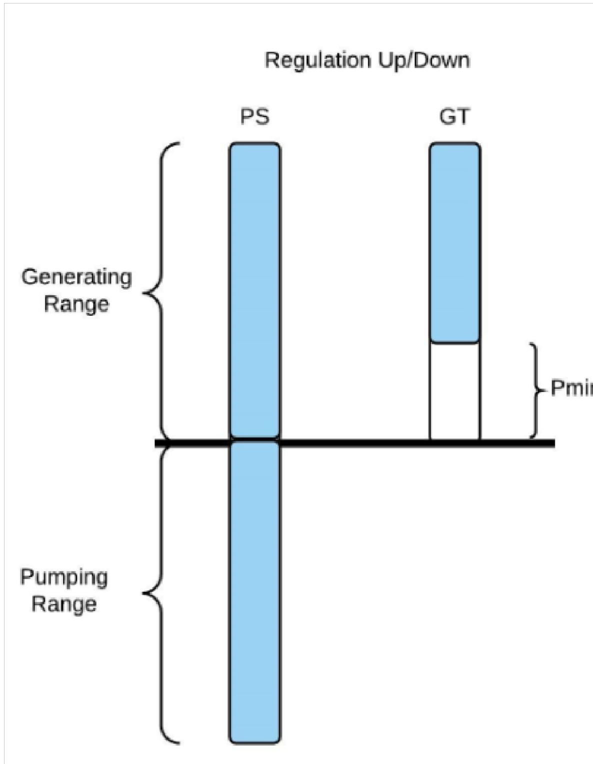


Assuming operating state is at optimal position for providing frequency response [ex. GT at Pmin]

Flexible Capacity: Regulation Up/Down

- Secondary control - occurs within seconds to minutes via automatic generation control
- Provided by generators who are online and have capacity to increase or decrease output

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Capacity to increase/decrease system output by reducing/increasing generation or load • Fast switching between modes doubles the effective range unit.	200%	$1,220
ICE	Capacity of conventional generators to provide regulation up and down is limited by ramp rate and minimum power generation levels.	79%	$2,320
Aero		47%	$2,843
Frame†		87%	$1,647



*Assuming operating state is at optimal position for providing frequency response [ex. GT at Pmin]

†Frame units are not usually used for Regulation given their limited operating flexibility

Spinning vs. Non-Spinning Reserves

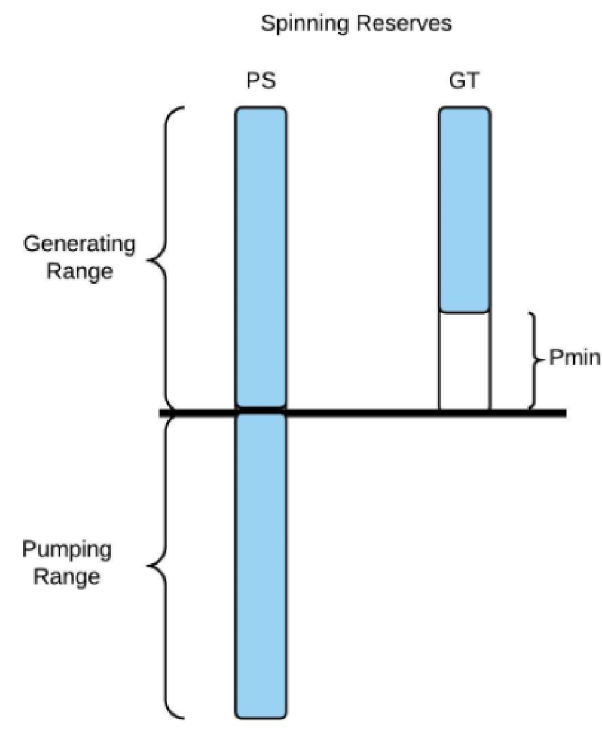
- Spinning/Non-spinning reserves are used to meet the same operating reserve obligation

- Fast response of ternary pumped storage units allows for provision of either spinning or non-spinning reserves, even when in charging mode

Flexible Capacity: Spinning Reserves

- Tertiary control - system operator dispatches reserves in response to contingencies
- Provided by units that are synchronized to the grid and able to ramp up within specified time frame

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Fast ramp rate and mode switching allows for fast response to operator dispatch • Unit in generation, idling, or pumping mode • Can increase/decrease load or generation • Can switch from one mode to another	200%	$1,220
ICE	• Limited by ramp rate, start-up times (hot-start)	79%	$2,320
Aero		47%	$2,843
Frame		87%	$1,647

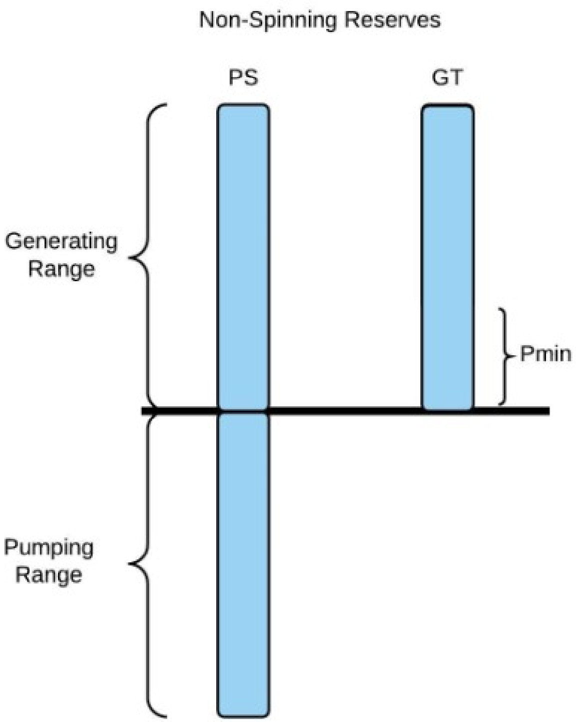


*Assuming operating state is at optimal position for providing frequency response [ex. PS pumping, GT at Pmin]

Flexible Capacity: Non-Spinning Reserves

- Tertiary control - system operator dispatches reserves in response to contingencies
- Provided by units that *are not necessarily* synchronized to the grid, but able to ramp up generation within specified time frame
- Required response time is slower than spinning reserves

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PSH	• Unit in standby mode • If dispatched, can quickly ramp up capacity	200%	$1,220
ICE	• Capacity and participation limited by ramp rate, start up time (cold-start)	100%	$1,833
Aero		100%	$1,336
Frame		100%	$1,433



*Assuming operating state is at optimal position for providing frequency response [ex. PS pumping, GT not on]

Additional Flexible Capabilities

Operating Characteristic	Gordon Butte Pumped Storage Quaternary Unit	Aeroderivative CT	Frame CT	ICE
Additional cost for each start	Minimal	Yes	Yes	Yes
Estimated median cold start cost*	n/a	$32/MW	$103/MW	Not provided
Can absorb overgeneration?	Yes	No	No	No
Black start?	Yes	Yes**	Yes**	Yes**

*Intertek APTECH (2012). Power Plant Cycling Costs. http://wind.nrel.gov/public/wwis/aptechfinalv2.pdf

**Siemens (2006). Black Start Studies. https://w3.usa.siemens.com/datapool/us/SmartGrid/docs/pti/2006June/Black_Start_Studies.pdf

Conclusions

- **Compared to the conventional resources described in NWE's 2019 Electricity Supply Resource Procurement Plan, Quaternary Pumped Storage can provide the following services at a cheaper per-kW installed price:**
  - Frequency Response
  - Regulation Up / Down
  - Spinning Reserve
  - Non-Spinning Reserve
- **Beyond the ability to provide flexible and peak capacity considered here, this analysis does not reflect a pumped storage facility's ability to store energy for use later, which enables**
  - Absorption of overgeneration
  - Arbitrage of energy price spreads
  - Increased transmission system utilization

Assumptions

		Quaternary Pumped Storage	Natural Gas Simple Cycle†		
Operating Characteristic	Units	Pumped Storage Hydro (PSH)*	Internal Combustion Engine (ICE)	Aeroderivative Combustion Turbine (Aero)	Frame Combustion Turbine (Frame)
Min Run Time	Hours	not reported	1	8	8
Min Down Time Operating Range	Hours [min –max, as % of capacity]	not reported -100% (pumping) – +100% (generating)	1 21%-100%	7 53%-100%	7 13%-100%
Min Run Time Min Down Time	Hours Hours	not reported not reported	1 1	8 7	8 7
Operating Range	[min –max, as % of capacity]	-100% (pumping) – +100% (generating)	21%-100%	53%-100%	13%-100%

DRAFT RESULTS - FOR DISCUSSION ONLY

Comments of Haymaker Wind, LLC

NorthWestern Energy's Draft 2019 Resource Plan

May 3, 2019

Haymaker Wind LLC (Haymaker), developer of the Haymaker Ranch Wind Energy Project (Haymaker Project), offers these comments in response to NorthWestern Energy's Draft 2019 Resource Plan.

Introduction

Haymaker has carefully reviewed NorthWestern Energy's (NWE) 2019 Draft Resource Plan and looks forward to participating in a future Request for Proposal. The planned Haymaker Project is a new wind energy project located on a large ranch, owned and operated by a single landowner in central Montana. The wind farm is sited in an area with world-class wind resources based on data collected from three met towers on the site since 2014. Interconnecting directly to the Colstrip Transmission System, with a high capacity factor, the project is in advanced stages of development. The project has been designed to be flexible in size but has the potential to produce over 600 MW of high-quality wind energy. The Haymaker Project can be sized to meet NWE's needs and still export additional power to other customers in the region. To provide additional optionality, the project owners submitted an additional 200 MW interconnection request to NWE's 230 kV transmission system. Haymaker completed a *Regulatory and Environmental Constraints Analysis* which found no fatal flaws or roadblocks for project development. Haymaker initiated additional critical path environmental studies in 2018, all of which relate to characterizing risk to species protected by the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act. Based on these development milestones, the Haymaker Project is capable of reaching commercial operations in 2021 and can qualify for federal tax benefits through 2023.

Haymaker believes Montana wind, or a combination of Montana wind and storage can provide low-cost benefits to NWE's system and customers. The project is located near the 500 kV Colstrip transmission system and the Gordon Butte Pumped Storage Hydro Project (Gordon Butte). Gordon Butte is a 400 MW, closed-loop pumped storage hydro (PSH) project with 3,200 MWh of storage capability and a planned interconnection to the Colstrip 500 kV transmission lines near Martinsdale, Montana. These projects provide NWE with an opportunity to combine resources and avoid a rush to natural gas that may ultimately result in costly stranded investments in natural gas-fired power plants.

Response: This issue is addressed in Chapter 11, Response to Public Comments.

Tax Benefits for Replacing Montana Coal with Montana Wind

The federal Renewable Electricity Production Tax Credit (PTC) allows 100% capture of the value of the PTC for projects that begin construction in 2016, 80% capture for beginning construction in 2017, 60% for construction in 2018, and 40% for 2019. To qualify for the PTC, a developer may either begin continuous construction of a significant nature on a project or reach the PTC safe harbor by spending at least 5% of the total capital cost of a project and subsequently making continuous efforts to complete the project. Under either case, the Internal Revenue Service (IRS) determined that should a project become operational within four years from the start of construction, the project will be considered to have satisfied the test for continuous construction and will thus avoid additional scrutiny by the IRS to determine whether or not the project was actually continuously constructed.[1] By acting now, NWE still has time to take advantage of expiring PTC for wind produced in Montana. These tax credits have benefitted customers by providing low-cost, clean, renewable energy for years, but are phasing out and will no longer be available after 2023. Based on the "four-year rule" described above, qualified projects procured soon and operational by the end of 2021 would qualify for the credit at 80 percent of full value. Eligible projects operational by 2022 receive 60 percent of the total value and 40 percent by 2023. NWE should consider taking advantage of this financial benefit for wind resources sooner, rather than later. The Haymaker Project can qualify for some level of the PTC through 2023 and is capable of being operational by 2021, providing NWE with options for achieving maximum tax benefits.

Wind and Pumped Storage Hydro

The Haymaker Project is located in Wheatland County, on a single Montana landowner's ranch. Wheatland County (also a designated Opportunity Zone[2]) is home to some of the best quality wind resource in the state. The project is situated in proximity to the existing 500 kV Colstrip transmission system and the Gordon Butte PSH Project. These projects combined, create an attractive combination of resources easily collected and interconnected to existing transmission facilities.

Gordon Butte provides flexible storage capability and while PSH has traditionally been used to balance load, it can respond to shifts in wind and solar production and load. In fact, a new study by researchers at the Australian National University has identified 530,000 sites around the world suitable for PSH facilities. However, much less than 1 percent of these potential PSH sites would be needed to support a 100 percent renewable global electricity system[2]. While the perception has been there are limited sites suitable for PSH, the already licensed Gordon Butte PSH project will employ the latest ternary pump/turbine technology to provide fast-ramping flexible capacity

---

[1] Renewable Electricity Production Tax Credit (PTC), Energy.Gov, https://www.energy.gov/savings/renewableelectricity-production-tax-credit-ptc, (May 24, 2018) [2] Opportunity Zones Frequently Asked Questions, IRS, https://www.irs.gov/newsroom/opportunity-zonesfrequently-asked-questions, (May 3, 2019)

[2] Evarts, E. (2019, April 3). Pumped hydro could deliver 100 percent renewable electricity. Retrieved from https://www.greencarreports.com/news/1122395_pumped-hydro-could-deliver-100-percent-renewable-electricity

ideally suited for integrating intermittent renewable resources into NWE's transmission grid. Unlike fossil fuels, there are no greenhouse gas emissions or cooling requirements with PSH and the environmental impact is kept to a minimum as it does not involve any river systems.[1] Gordon Butte coupled with Montana's robust wind resources provides a reliable, cost-competitive, and carbon-free solution to NWE's system needs.

Risks of Natural Gas versus Renewable Resources Plus Storage

Haymaker encourages NWE to carefully consider alternatives before pursuing a natural gas future. Advances in renewable energy and distributed resources combined with storage can lower rates and provide carbon free grid reliability without committing customers and investors to costly natural gas infrastructure and potentially volatile fuel costs. In fact, a study by the Rocky Mountain Institute recently found that new-build costs of clean energy portfolios are likely to beat just the operating costs of efficient gas-fired power plants within the next two decades.[5] This is a serious risk for any investors already pursuing gas-fired power plants and deserves careful consideration by NWE in its current deliberations. In Arizona last year, regulators rejected the resource plan of the state's major utilities citing too much reliance on natural gas and the risk of stranded assets. Those utilities are soliciting storage instead. In fact, many examples can be found of utilities shifting from natural gas plans to renewables plus storage.[6]

Further, the cost of natural gas power is based on the commodity price of natural gas, which is volatile. Alternatively, the price of controllable, storable renewable energy (PSH plus wind) is based on technology costs, which continue to decrease. Even if methane emissions are reduced, natural gas is still subject to future carbon pricing. Economists are starting to tout the benefit of fees on the production of carbon as a practical way to incentivize a wide range of industries to quickly reduce emissions.[7] If natural gas prices rise or a significant price is put on carbon in the next two decades, NWE customers and investors will be saddled with unnecessary costs for committing to a natural gas future or even as a bridge to the future. Instead, NWE should consider a wind plus storage solution given the resources and opportunities already in their own back yard.

Response: NorthWestern will conduct a competitive solicitation to acquire resources to meet the customer needs identified in the resource plan. The discussion of the competitive solicitation following the submission of the plan is contained in Chapter 13. We invite Haymaker and Gordon Butte to participate in NorthWestern's future competitive solicitations for resources.

[1] Nield, D. (2019, March 31) Huge Global Study Just Smashed One of The Last Major Arguments Against Renewables. Retrieved from https://www.sciencealert.com/scientists-spot-530-000-potential-pumped-hydro-sites-tomeet-all-our-renewable-energy-needs

[5] M. Dyson, J. Farbes, and A. Engel. *The Economics of Clean Energy Portfolios: How Renewable and Distributed Energy Resources Are Outcompeting and Can Strand Investment in Natural Gas Fired Generation*. Rocky Mountain Institute, 2018. www.rmi.org/insights/reports/economics-clean-energy-portfolios

[6] Roberts, D. (2018, Oct. 26). Clean energy is catching up to natural gas. Retrieved from https://www.vox.com/energy-and-environment/2018/7/13/17551878/natural-gas-markets-renewable-energy

[7] Clancy, H. (2018, Sept. 24). The case for valuing carbon is growing louder (even though "tax" is still a dirty word). Retrieved from https://www.greenbiz.com/article/case-valuing-carbon-growing-louder-even-though-tax-still-dirtyword

Missoula City-County Board of Health

Missoula Public Health httpstos•]/www.missoulacountv.usJqovernmentïheaEth/health-departmentJboards-cou0Cils301 West Alder Street I Missoula MT 59802-4123
Gty-County HealthDepartment ADMINISTRATION

Phone | 406.258.3376
Fax | 406.258.4857

April 18, 2019

NorthWestern Energy I
l E Park St.
Butte, MT 59701-171 1

Attention: 201 9 Electrical Supply Resource Procurement Plan

Dear Sir or Madam:

The Missoula City-County Board of Health (Board) appreciates the opportunity to comment on NorthWestern Energy's 2019 Electrical Supply Resource Procurement Plan (Plan). The Board administers matters pertaining to environmental and public health in Missoula City and County. NorthWestern Energy's Plan should chart a path towards renewable energy sources and away from fossil fuel. A healthy environment and a reliable energy supply that minimizes impacts to the climate are crucial to Montana's economy and future. Missoula City and County are actively working to transition away from fossil fuel electrical power to renewable energy sources.

When NorthWestern Energy (NWE) considers energy production for Montana's future, the Board recommends the following to reduce fossil fuel use and accommodate a transition to renewables:

1. Continue to reduce carbon emissions and develop a plan to replace the power from Colstrip Unit 4 with renewable energies. Develop a modeling scenario where the Colstrip Unit 4 closes by 2027 or earlier, rather than the proposed 2042 closure.

   Response: This issue is addressed in Chapter 11, Response to Public Comments.

2. Invest in clean, renewable energy sources that produce less pollution and minimize greenhouse gas releases. With as much as 3000 MW of renewable energy development being studied and/or proposed in Montana, NWE should investigate, encourage and budget for the best of them. For example, the Haymaker Ranch Wind Energy Project near TwoDot proposes a 355 MW windfarm and is near transmission lines that will be available when Colstrip Units 1 and 2 shut down. Make contacts with potential renewable energy producers.

   Response: This issue is addressed in Chapter 11.

3. Develop energy storage capacity and research new ways to store energy when renewable energy is abundant. Study the Gordon Butte Pumped Hydro Storage Project to fill the supply gaps in wind power. This is a decades-old technique, and very economical once built.

   Response: This issue is addressed in Chapter 11 and in our response to comments from Gordon Butte.

4. Reinstate NWE's energy audit program for customers' homes and provide incentives to make the recommended efficiency improvements. Improved heating and cooling efficiency for buildings will directly impact peak energy needs during the hot and cold extremes that concern NWE.

   Response: NorthWestern continues to offer its E+ Audit for the home through the Universal System Benefits (USB) program. Current program offerings can be found at www.NorthWesternEnergy.com/Eplus.

5. Emphasize energy efficiency measures to reduce energy demand. Demand-Response is one method wherein businesses or individuals reduce energy consumption during peak periods, thus avoiding higher peak energy costs. This is being applied in several states. Model these techniques for a Montana application.

   Response:

   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 to complete this work, which is expected to be finalized in 2019. The results of these activities may result in adjustments to the forecasts noted in this plan.

6. Pursue geographic diversity among renewable energy facilities. Diversity of sites and methods makes the availability of a renewable energy source (wind, solar, geothermal, biomass) more likely at any given time.

   Response: NorthWestern resource plan examines generic (not-sited) resources. Site specific information will be obtained, and evaluated, in future competitive solicitations.

7. Contract with existing integration power plants in the region for peak demand periods.

   Response: This issue is addressed in Chapter 11.

8. Improve weather and energy output forecasting tools in order to anticipate special needs.

   Response: This issue is addressed in Chapter 11.

9. Investigate entry into a regional energy market. Contact other energy producers to see how you could accommodate each other's needs

   Response: This issue is addressed in Chapter 11.

Carbon dioxide emission into the atmosphere is the major contributor to global climate change and has serious impacts on Montana's recreation, agriculture, silviculture and people's health. Longer wildfire seasons caused by warmer and dryer conditions are increasingly hazardous. Wildfire smoke aggravates heart and lung diseases such as heart attacks, stroke, chronic obstructive pulmonary disease and asthma. Pregnant women, children and the elderly are more susceptible to smoke impacts than other groups.

Carbon-free energy is what customers are demanding in our export locations and, increasingly, in Montana. Burning fossil fuels is dangerous to Montana and the planet. Over the long term, the fossil fuel natural gas should only be used, if at all, for integrating wind and solar. Ultimately, renewables combined with energy storage are the future. Renewable energy sources provide good paying jobs throughout the state and are less prone to the boom and bust cycles of fossil fuels.

We encourage NorthWestern Energy to embrace renewable energy sources and energy conservation in its energy procurement plan. Continued reliance on coal is harmful to public health and an economically shaky endeavor.

Sincerely,

Ross D Miller

Ross Miller, Chair
Missoula City-County Board of Health

cc: Montana Consumer Council
State of Montana Governor Steve Bullock

CITY OF MISSOULA MISSOULA COUNTY

BCC 2019-077
May 2, 2019

Mr. Robert Rowe,
President and CEO
NorthWestern Energy 11
E. Park St.
Butte, MT 59701

Dear Mr. Rowe:

Thank you for the opportunity to comment on NorthWestern Energy's Draft 2019 Electricity Supply Resource Procurement Plan.

In April 2019, the Missoula City Council and the Missoula Board of County Commissioners, with the support of hundreds of local residents, businesses and community organizations, adopted a goal of 100% clean electricity by 2030 for the Missoula urban area. There is truly broad public support for this initiative. And that support is not limited to Missoula. Nonpartisan polling has found that 90% of Montanans support increased use of solar energy, and 86% support increased use of wind energy to meet our state's future needs. Across the country, more than 130 local governments have committed to 100% clean energy, and many are working directly with their local utilities to achieve this transition. Investor-owned utilities that have committed to achieve 100% carbon-free electricity include Idaho Power, Rocky Mountain Power, Xcel Energy, Green Mountain Power, the Public Service Company of New Mexico and Avista, as well as a number of municipal utilities and electric cooperatives.

Approximately 95% of the electricity consumed in the Missoula urban area is purchased from NorthWestern Energy; both City and County governments are NorthWestern Energy customers, as are the majority of the 117,000 residents we represent. We are acutely interested in NorthWestern's Electricity Supply Resource Procurement Plan. NorthWestern's approach to resource procurement has great potential to help or hinder our efforts, as well as to benefit, or detract from, the economic and environmental health of our community.

The Draft Resource Procurement Plan emphasizes that NorthWestern intends to pursue "lowest cost" resources. We ask that you consider the full, long-term costs of energy resource choices as you make decisions that have such profound effects on our future. Please consider the longterm costs of climate change and do a complete accounting. A Yale University article from April 2019 estimates that if we do nothing, annual costs associated with climate change will exceed $220 billion. Over the long-term, a transition to more renewables will save money. As you know, the price of solar and wind technology has declined precipitously in recent years, and the costs of energy storage technologies, especially batteries, are declining even faster. Renewable resources also have the advantage of zero fuel cost, reducing the risk of price volatility for consumers. They do not require the construction of costly fuel infrastructure such as gas pipelines. They do not emit hazardous air pollutants or greenhouse gases, and, unlike thermal power plants, solar and wind farms will never leave their owners on the hook for massive cleanup costs.

Response: This issue is addressed in Chapter 11, Response to Public Comments.

As we look ahead to 100% clean electricity, we are starting in a strong position. 61% of NorthWestern Energy's current generation portfolio is carbon-free, and we greatly value these existing hydroelectric, wind and solar resources. But we believe that we can, and must, go further. We understand that reaching 100% clean electricity — or even 90% — will not be easy. How will NorthWestern Energy work with us and learn from other local governments and utilities that are finding innovative ways to make this transition? We believe that a commitment to renewable electricity has the potential to benefit both Missoula and NorthWestern Energy. This transition can facilitate the creation of a profitable, forward-looking business model that will sustain your company and our community well into the future. How will Northwestern Energy start planning for and investing in that future now? We look forward to learning how the revised Resource Procurement Plan will catalyze our broadly supported transition to clean electricity by 2030.

Response: NorthWestern looks forward to working with City of Missoula and Missoula County as they implement their clean energy plan.

Sincerely,

Sincerely,

City of Missoula

John Engen, Mayor

Bryan von Lossberg, Council President siden

Missoula Board of County Commissioners

Nicole Rowley, Chair

Dave Strohmaier, Commissioner

Josh Slotnick, Commissioner

BCC/ac

May 7, 2019

John Bushnell
NorthWestern Energy
400 Oxford Street Butte,
MT 59701

Subject: **NorthWestern Energy Supply Plan Comments Submitted by the Montana Energy Office**

Dear Mr. Bushnell:

The Montana Energy Office (MEO) at the Department of Environmental Quality (DEQ) appreciates the opportunity to participate in NorthWestern Energy's (NWE) Electric Technical Advisory Committee (ETAC) and to submit comments on the draft electricity supply resource procurement plan.

In general, the MEO believes NWE's planning process improved this planning cycle. The number of ETAC meetings has increased and importantly, the content of the meetings was improved to make them more relevant to providing input into the plan itself. Additionally, MEO applauds the inclusion of public meetings. These were well organized, and the content provided by NWE was relevant to the audience. MEO strongly believes in the importance and value of public input and appreciates NWE's inclusion of public opinion into the process.

While the process was improved, it was not without its flaws. ETAC recommendations during meetings were still generally met with resistance if they did not align with the precise direction NWE had established. Acknowledging that ETAC is non-binding, it would improve the overall product (e.g., the plan) if NWE's rationale for not seriously entertaining ETAC member recommendations were more fully explained and discussed with the group. In addition, communication with ETAC members and the public was not consistent and could be improved. For example, there was no ETAC meeting after the draft procurement plan was released in March of 2019. The inability of ETAC members to see Volume 2 until after the release of the final report makes it difficult for members to provide fully informed comments on the draft. Furthermore, the modeling that went into this plan still seems to be taking place in a black box as members have no access to the results of the model. Overall, NWE began with an improved process including public engagement but seemed to disengage from the ETAC in the final few months of the process.

<u>Specific Comments on the plan</u>

Page 1-3: What are the assumptions built into 'Figure 1-1, Peaking Capacity Needs'? To properly explain this table, more detail is needed on which supplies are going off-line in NorthWestern's system year by year (perhaps in table form). For example, what causes the slight modulation in peak capacity needs in 2029 and the slight drop-off in 2035 in Figure 1-1?

Page 3-3: Please fix the labeling in Figure 3-1. The existing labeling is confusing and perhaps even incorrect. For example, the line representing retail load with demand side management (DSM) and net energy metering (NEM) is shown as higher than retail load without DSM and NEM. This seems to be incorrect.

Response: Figure 3-1 was mislabeled and has been corrected.

Page 3-6: The Navigant NEM adoption forecast in Table 3-3 may be unreasonably high. MEO suggests that NWE provide a NEM level that reflects proposed changes to the NEM tariff in the rate case, perhaps in a sensitively analysis.

Response: The NEM adoption rate was determined in a third party study conducted by Navigant Consulting. The adoption forecast will remain unchanged

Page 3-8: What is the capacity contribution Navigant assumed for solar? How does the Montana Eighth Judicial District Court decision in Cause No. BDV-17-0776 on April 2, 2019 affect NorthWestern's calculation of solar capacity contribution and potentially reduce the need for flexible capacity to manage increased renewable energy interconnection?

Response: NorthWestern has not incorporated any potential effects of the decision. We disagree with the solar capacity contribution finding and the decision has been appealed.

Page 4-13: Table 4-14 lists Ryan and Cochrane dams as having negative values for Decrement Bid (DEC). What does it mean to have negative values for DEC?

Response: The negative value for decrement (DEC) means that NorthWestern would be able to reduce generation as necessary up to that amount.

Page 4-24: Table 4-9. The 'reduced revenue costs' argue that net metering has a large overall cost on the value streams of the system (these costs drive the study results), however there is no explanation for those costs nor are the 'reduced revenue' results explained in any detail. Please explain more fully the 'reduced revenue costs' in the Net Energy Metering Study.

Response: The NEM study was conducted by Navigant Consulting and the full study will be included in Volume 2 of the 2019 Plan.

Page 6-18: Figure 6-7 is difficult to read, even when zoomed in. MEO would suggest taking out most of the existing labels and adding a few larger labels that describe the natural gas lines generally.

Response: The map is not intended to show detailed information.

Page 7-20: When talking about adding natural gas, please address the challenges and costs with the natural gas transmission system (which is already at or near capacity much of year) and the resulting impacts on the electricity system. For example, the capacity factor for natural gas electric generation overall in Montana might go down slightly if the gas transmission system is full or near full, and thus generator curtailments occasionally happen. This should be taken into consideration for the next modeling round.

Response: Except for the DGGS upgrade, the resource plan models generic resource types. Generic resources are not located, or tied to a location. The natural gas system impacts discussed in this question will be taken into account when natural gas-fired thermal resources are evaluated in the context of the competitive solicitation process that NorthWestern will rely upon to fill our customers' identified resource needs.

Page 9-19: The plan states that, "NorthWestern's share of the capital and financial assurance costs associated with the AOC are incorporated into the cost structure for Colstrip in this plan". Please explain more fully how the AOC costs are incorporated into the plan. Please explain how, or if, these remediation costs will figure into future resource acquisitions.

Response: AOC costs experienced through the planning horizon are included in the Existing Resource Fixed Costs (as part of the Revenue Requirement for Colstrip) in this plan. These costs are included in every portfolio and therefore do not affect the selection or timing of additional resources.

Page 10-23: Figure 10-5 is very confusing and nearly unreadable and would benefit from better labeling.

Response: The graph is not meant to be read for its detail, it is designed to show in graphic form what the narration on the graphic details in text.

Page 10-25: What is the conclusion of Chapter 10? There is a lot of data and charts, but there appears to be no solid conclusion. A couple more sentences at the end of the Conclusion section on page 10-25 would be useful to better explain how NorthWestern will use the modeling results to guide their solicitations.

Response: NorthWestern will be using the model developed for the resource plan to evaluate bids in competitive solicitations, but the results of portfolio modeling for the 2019 Plan are only indicative and are only a "snapshot" in time. Future solicitations will be guided by our customers' resource needs and not by the results of portfolio analysis.

Page 11-2: The plan seems to indicate the only way NWE can meet the reserve margin for the EIM is to own the resource or enter into long-term contracts. Does the plan consider the option of balancing out risk with some exposure to the market for only a few hours a year? If so, this is not apparent in the plan. The Mid-C market has generally had low prices which NorthWestern currently takes advantage of. The need to be completely whole for peak demand is not fully explained or clearly justified in the plan.

Response: Yes, as explained in our last response below, the need to address our capacity deficit is not an EIM issue, it is an RTO issue.

General Comments on the Plan

If NWE intends for the public to comment on this plan, then the plan should be organized in a way that is more digestible for the lay person. The executive summary in the current plan is a good start. Easily digestible charts should be included in the executive summary. Figures 1-1 through 1-4 in the executive summary are fairly good, while 1-5 and 1-6 should probably be included in the main text. Table 1-1, the crux of the plan, could be expanded into a chart.

Response: This resource plan attempts to balance the diverse needs of the plan's audience. We appreciate the feedback.

NWE talks thoroughly in the plan about becoming 'whole' for the Energy Imbalance Market (EIM) market, but does not make a case for the cost of becoming whole on rate payers. Becoming whole in those few hours of deficit during the year can be done by purchasing energy on the market.

Response: The issue is not becoming whole for EIM entry, it is becoming whole so that NorthWestern will be positioned for RTO entry. An RTO will require that NorthWestern carry a planning reserve margin to participate. As RTO formation takes place, the rules governing required capacity and planning reserves , and how much can be met with market purchases, will be established by the RTO and NorthWestern will adjust its resource acquisitions accordingly. Currently NorthWestern is a long way from becoming 'whole' and, barring unusual circumstances, will not become whole prior to conclusion of another planning cycle in which this issue will be revisited.

If you should have any further additional questions, please do not hesitate to contact me at 406-4440218 or jblend@mt.gov.

Sincerely,

Jeff Blend
Montana Energy Office, Energy Bureau, AEM Division
Montana Department of Environmental Quality
P.O. Box 200902
Helena, MT 59620-0901

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

*****

IN THE MATTER OF NorthWestern Energy's 2019 Draft Electricity Supply Resource Procurement Plan	) REGULATORY DIVISION)) DOCKET NO. N2018.11.78

COMMENTS OF THE MONTANA ENVIRONMENTAL INFORMATION CENTER

May 5, 2019

The Montana Environmental Information Center (MEIC) appreciates the opportunity to comment on NorthWestern Energy's 2019 Draft Electricity Supply Resource Procurement Plan. MEIC is a member of the Energy Technical Advisory Committee (ETAC), has participated in NorthWestern's resource planning process for several planning cycles, and submits the following comments.

Overall Comments

Comment:
It was difficult to comprehensively review and comment on the draft plan due to Volume 2 not being publicly released along with Volume 1. This lack of transparency was disappointing. The final plan should strive to improve transparency and include all documents associated with its creation when it is submitted to the PSC.

Response: Mr. Brian Fadie is MEIC's representative on NorthWestern Energy's ETAC committee. On March 13, 2019 Mr. Fadie asked if Volume 2 would be available prior to the filing of the 2019 Plan with the Commission. Mr. Bushnell, Manager of Energy Supply Planning and Regulatory responded within the hour that Volume 2 would not be filed prior to the submission of the 2019 Plan to the Commission, but that NorthWestern would try to accommodate requests for Volume 2 information (see clip below). NorthWestern's ETAC group was copied on the email. NorthWestern did not receive any requests for Volume 2 information from members of ETAC, but did receive and respond to requests for information from Renewable Northwest. NorthWestern provided a good faith response to Mr. Fadie to provide information.

From: Bushnell, John
Sent: Wednesday, March 13, 2019 1:41 PM
To: 'Brian Fadie' <bfadie@meic.org>
Cc: ETAC Mailing List
Subject: RE: Draft - 2019 Electricity Supply Resource Procurement Plan

Deigo asked the same question last week. No, Volume 2 will not be available until the plan is filed with the MPSC.

Let me know what you're interested in and maybe it's in a form that can be easily provided prior to the formal filing.

Thanks,

JB

NorthWestern assumed that Mr. Fadie participated in good faith when he attended ETAC meetings, but many of his concerns expressed here were not expressed at ETAC.

Comment:
The draft plan contains significant shortcomings that challenge its status as a least-cost plan. Thankfully, the final plan is not due until December 15, 2019, giving enough time to remedy concerns and create a plan that can give ratepayers and all stakeholders confidence in its conclusions. There is no rush to complete the final plan. In fact, the opposite would seem to be true: the PSC has specifically made enough time available to get the plan right. It would be shameful if after three years since the previous plan was submitted, and more than a dozen planning advisory committee meetings, the 2019 final plan were to be rushed and completed in a shoddy manner. Again, thankfully, there is time available to get it right.

Response: As MEIC knows, this plan is the culmination of a process that began in November 2016 and represents the longest planning process that NorthWestern has ever undertaken. NorthWestern has not "rushed" to complete the draft or final plan.

Chapter 2

Comment:
Page 2-9 states, "…recent studies question the ability of the regional power supply to meet future capacity needs." The final plan should disclose that NorthWestern Energy was a cosponsor of the referenced study as well as if the company contributed financially to its creation.

Response: This issue is addressed in NorthWestern's response to public comments in Chapter 11, Response to Public Comments.

Comment:
The final plan should use the latest information available to make a reasonable assessment of not only resources coming offline in the region but also resources coming online. It is not adequate to claim the regional supply of market energy is becoming scare due to other utilities closing power plants unless a fair assessment is made of new energy sources that may be

coming online in the region (including the contributions of energy efficiency and demand side management programs).

Response: This issue is addressed in Chapter 11.

Comment:
Page 2-14 states "…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." However, Table 3-3 on page 3-6 notes that from 2028-2038, or half the term of the planning period, summer peak demand is expected to be greater than winter peak demand. Table 3-3 also notes summer peak was greater than winter peak in 2012, 2015, 2016, and 2017. The final plan should make clear that NorthWestern is a dual peaking utility with winter and summer peaks and that this is trending toward summer peaking.

Response: Response: The 2016 peak customer load occurred in winter, not in summer as Mr. Fadie asserts. NorthWestern has always described its customer loads as "dual-peaking" but that our largest peak loads and our greatest challenge in meeting peak demand occurs in winter. The data in Table 3-3 does not support the assertion that NorthWestern is "trending toward summer peaking."

Chapter 3

Comment:
The draft plan assumes Colstrip will operate at least through the plan's 20-year time horizon of 2039. This places ratepayers at extreme risk by ignoring the countless warning signs that the facility will all but certainly close much earlier, including no-coal legal requirements for utilities in Oregon and Washington by 2030 and 2025, respectively. Pretending Colstrip will never close undermines the least-cost credibility of the plan, exposes ratepayers to poor decision-making by the utility, and ultimately exposes ratepayers to the risk of paying too much for energy. To protect ratepayers from future risks, the final plan should model a scenario where the Colstrip power plant retires in 2025.

Response: This issue is addressed in Chapter 11.

Comment:
Since the completion of the Navigant net metering study, NorthWestern has proposed in its rate case significant changes to the economics of installing a net-metered system. Presumably, the company believes its proposed changes to net metering are proper, correct, and will be adopted by the Commission. Were this to happen, the adoption rate of net metered systems would change, likely dramatically. The final plan should model an adoption rate for net metered systems that takes into account the modified rate structure and demand charges that are proposed by NorthWestern in the rate case.

Response: NorthWestern cannot wait for the final disposition of NEM issues prior to filing its final plan with the Commission. Moreover, the impacts of NEM are currently minimal.

Comment:
The final plan should take into account the ruling of the state district court in the QF-1 case (Docket D2016.5.39) and make any modifications necessary to match the requirements of that ruling, including carbon avoidance values and capacity contribution for solar systems.

Response: This issue is addressed in Chapter 11.

Chapter 4

Comment:
Page 4-6 states "NorthWestern's current portfolio of resources is shown in Table 4-1." However, as noted in footnote 1 on page 4-6, South Peak Wind, Crazy Mountain Wind, and MT Sun are not yet commercially operable, meaning they are not currently producing energy for the portfolio. Further, there is uncertainty (and perhaps significant uncertainty) about whether all of these projects will ever become operational. The final plan should refrain from making statements that can mislead readers, such as stating a resource is part of the "current" portfolio unless it is actually in operation as of the writing of the plan. Instead, these resources should be labeled in a more accurate manner, such as anticipated or potential future resources.

Response: NorthWestern must consider these resources viable projects until they either default on their contact, or withdraw their projects from consideration. The statement is not misleading. This issue is also addressed in Chapter 11.

Comment:
Table 4-2 on page 4-11 could benefit from additional explanation. Why was the capacity contribution of Basin Creek 0% and DGGS only 0.5%? Does Basin Creek ever contribute toward peak hour demand? If so, why was it contributing nothing during this time? A definition of "DGGS (Full Generation)" and an explanation for why, according to this table, that facility was only producing 6 MW of its 150 MW nameplate capacity would be helpful.

Response: The table is based upon the actual peak load hour on the peak load day for 2017, the reason that Basin Creek and DGGS show a 0% and 0.5% contribution on that day is because NorthWestern dispatches generation based upon economics, and on the peak day market purchases were lower cost than the operating costs of Basin Creek and DGGS.

Comment:
Table 4-6 and 4-7 indicate NEEA DSM acquisition and NEEA forecast program expenses remain essentially constant for every year after 2018-2019. However, this portrayal of NEEA activities does not seem to be accurate. NEEA's future DSM savings and program expenses are not well known beyond its current program plan, which lasts five years or less. Further, NorthWestern's

participation in NEEA's current or future programs is not certain, making none of the listed DSM or program spending certain either. At the least, it would not be accurate to portray the NEEA DSM acquisition or program expenses from at least 2025 to 2035 as either known amounts or guaranteed to happen. The final plan would benefit from giving more explanation about NorthWestern's role in NEEA, the company's plans for current and future program participation, and more accurately convey the uncertainty around future NEEA DSM acquisition and program spending.

Response:

The forecast NEEA DSM Acquisition is estimated based on conservative historic acquisition and the early information provided for the 2020-2024 Business Plan. 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.

Comment:
Table 4-5 could be improved for clarity. It is impossible to tell whether the amount spent in a given year was over, under, or the same as the amount budgeted. It also cannot be discerned whether the DSM savings achieved was higher, lower, or the same as the amount that was targeted. Previous Resource Procurement Plans have more clearly laid out this information so the reader can understand what is going on with DSM spending and acquisition.[1] The final plan would benefit from returning to that format and making this information more clear and accessible.

Response:

Table 4-5 has been updated to reflect budget and spend for DSM and NEEA and acquisition target and acquisition reported for DSM, NEEA, and USB.

Chapter 5

Comment:
Page 5-5 notes that to participate in the EIM in a given hour, and thus access savings, a utility must be resource sufficient. However, NorthWestern is not resource sufficient in all hours and it would likely require investments of hundreds of millions of dollars to do so. The final plan should outline 1) whether the E3 or Utilicast studies assumed NorthWestern would be resource sufficient in all hours when participating in the EIM or just some, and 2) the estimated cost to build or acquire the resources necessary to reach that level of resource sufficiency, what those resources were, and how those costs were calculated. The final plan should also include in its Volume 2 or elsewhere the full E3 and Utilicast studies for transparency and review.

[1] See Table 3-1 on page 3-4 of the 2015 Resource Procurement Plan

Response: Note that resource sufficiency is not equivalent to resource adequacy. Resource adequacy refers to the long-term capacity needed to meet peak load under all potential weather and system conditions. It is in this planning context – the subject of this Plan – that long-term alternatives are examined. Resource adequacy is not addressed by EIM.

Resource sufficiency, in the context of EIM, means that an entity has the resources to meet its load obligation and the flexibility to meet the potential ramping of its load and variable energy resource output *for the given hour*. As a Balancing Authority, NorthWestern already has this obligation under NERC standards. While EIM will quantify the specific requirements, we expect to continue to be able to meet our obligations using a similar approach to what we use now.

Neither the E3 nor the Utilicast studies specifically examined the resource sufficiency calculations for NorthWestern or estimated the number of hours that we would pass the tests.

Comment:
Page 5-10 notes the draft plan assumed full RTO participation in 2025. Due to the massive amount of uncertainty surrounding this scenario, it is unwise for this assumption to be the only one modeled in the final plan. Despite the justifications listed on pages 5-9 and 5-10, there is no certainty whatsoever about:

1. Whether a west-wide RTO will ever form.
2. Whether it would be in 2025 or some other year.
3. What other utilities would participate in an RTO at all, whether other utilities would begin participating in 2025 or (as happened with the EIM) join at a staggered pace over a number of years, and what the makeup of other utilities portfolios will be in 2025.
4. What an RTO's participation and market rules would be, for example:
    a. Whether full resource sufficiency would be needed in all hours or on an hour-by-hour basis.
    b. Any entry and/or exit fee.
    c. The value of energy at different hours of the day and different times of the year. For example, what is the value of energy in this RTO at 9pm on a weeknight in January when Montana wind is producing exceptionally well? NorthWestern may not need this energy itself, but it could be highly valuable to sell to into an RTO.
    d. How an RTO's participation rules and market makeup would impact the value of 200 MW gas peaker plant built today.
5. Whether joining an RTO would actually achieve overall savings for ratepayers given NorthWestern's portfolio and the other considerations listed above. If ratepayers do not achieve overall savings then NorthWestern may not join a future RTO. Whether the governance structure of the RTO would be acceptable to the Montana legislature, the PSC, and/or NorthWestern such that joining would be an option.

Given these significant uncertainties, and the fundamental impact this assumption of joining an RTO in 2025 has on the overall 2019 plan, the final plan should model an alternative scenario in which a west-wide RTO does not form and thus NorthWestern does not join it. While many signs may point to a west-wide RTO forming at some point, there are far too many unknowns at this point to make joining one in 2025 the only scenario modeled in the 2019 plan.

Response: as a Western RTO has not yet formed, this line of commenting is premature and NorthWestern is not able to provide a response. NorthWestern Energy is on a three year electricity supply resource procurement planning cycle and will continue to explore the changes in the RTO market development as those changes come to fruition.

Chapter 6

Comment:
The final plan should estimate in quantified terms the cost of new gas infrastructure, such as pipelines and storage tanks, that would be needed to operate a significant buildout of new natural gas electricity generation units on NorthWestern's system. Specifically, NorthWestern has discussed adding 200 MW of capacity every year for four years. Given Tables 10-2 and 10-4 note the "base" scenario of the draft plan selects only gas units to be built, it is reasonable to conclude that if this plan were to be followed all or most of this 800 MW capacity to come from gas units. The final plan should quantify the infrastructure costs that would be necessary to operate 800 MW of new gas capacity on NorthWestern's system. Without these estimates it is impossible to discern the actual cost of these gas units and undermines the ability of the plan to claim it is a least-cost plan. The final plan should also describe this necessary infrastructure, including how much new pipeline and storage infrastructure would be needed and where it would be located.

Response: This issue is discussed in Chapter 11.

Chapter 7

Comment:
Footnote 3 of Table 7-6 states "Capacity factors for dispatchable technologies assumed in order to develop O&M costs." The final plan should specify what capacity factors were assumed for these technologies and how they were chosen. Specifically, the assumed capacity factor for "DGGS Buildout" should be detailed given the uncertainty about how much that facility has historically operated.

Response: The development of resource costs is contained in the HDR report "Generation and Storage Resource Characterizations" contained in Chapter 7 of Volume 2.

Comment:
The discussion on pages 7-10 and 7-11 of battery energy storage systems and how their benefits were modeled does not make clear whether batteries were modeled to provide

ancillary services in addition to peak capacity or if they were only modeled to provide peak capacity. Table 7-4 notes batteries can provide ancillary services like “reg up/down, spin/nonspin, reserve” but it is not clear whether these services were actually included in modeling of battery system performance and benefits. The final plan should more clearly describe whether batteries were modeled to provide ancillary services in addition to peak capacity and if not why not.

Response: Batteries are modeled with the ability to serve load, dispatch economically in the market, and provide ancillary services, including Spin, Non-Spin, Reg Up, and Reg Down. In an hour, the battery can provide one or any combination of these benefits up to a combined total capacity of 25 MW, subject to operating constraints shown in Table 7-4. Batteries are dispatched as part of the optimization of the portfolio to maximize value to customers.

Comment:
Figure 7-2 shows the cost for wind energy increasing every year through 2050. It also shows solar increasing in cost until about 2021, when it declines briefly before continuing to increase in cost until 2050. Battery energy storage systems are show to increase in cost until about 2021 before staying the same for the next 20 years before finally seeing a small decline. These cost projections defy reality. The cost of wind, solar, and battery energy storage systems all have demonstrably and consistently been in decline for many years and future cost projections show continued price declines in the future.[2] The draft plan gives no explanation for why all three energy technologies would suddenly halt their cost declines and immediately begin cost increases, or in the case of batteries, remain exactly the same for more than 20 years.

Further, chapter 10 does not make clear which future cost assumptions were used when modeling any of the scenarios in the plan. Figure 7-2 notes two different forward costs assumptions, but again it is not clear which is used for modeling scenarios in the plan. Was the “wind – 100 MW Montana” forward price curve used - which in contrast to reality shows wind prices increasing right away and continuing to increase in perpetuity – or was the “Low-Cost Wind” price curve used? This is also unclear for solar and battery energy storage.

The final plan should explain which set of forward cost assumptions were used when modeling the scenarios in Chapter 10 and why those were chosen. Further, a detailed explanation and evidence will be need to be presented in the final plan if it chooses to continue to suggest wind, solar, and battery energy storage systems will suddenly and dramatically reverse their cost decline trends and instead rise in cost for the next 30 years.

Response: The discussion at the end of Chapter 7 has been revised. This issue is also discussed in Chapter 11.

---

[2] See Lazard 2018 Levelized Cost of Energy and Levelized Cost of Storage (https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018) and Lawrence Berkeley National Laboratory Tracking the Sun report (https://emp.lbl.gov/tracking-the-sun) and wind technologies report (https://emp.lbl.gov/wind-technologies-market-report/)

Comment:
Figure 7-3 contains an outlier when it shows a decline in cost for “Combined Cycle 2x1 CT – Frame/Industrial CT” during 2018 to about 2020. The final plan should explain why this cost decline is observed given it breaks sharply from the rest of the cost curves.

Response: The development of resource costs is contained in the HDR report “Generation and Storage Resource Characterizations” contained in Chapter 7 of Volume 2.

Comment:
During the 2019 Montana legislative session NorthWestern staff repeatedly made statements about the costs and benefits of purchasing an additional 150 MW share of Colstrip Unit 4, however no modeling or specific cost numbers was ever released publicly. Colstrip Unit 4 is no longer an unknown potential resource for NorthWestern and the company has clearly put extensive thought into purchasing an additional share. The final plan should disclose all modeling that analyzes the acquisition of an additional interest in the Colstrip plant, including all cost assumptions (including future cost scenarios, such as changes in cost when Colstrip Units 1 and 2 close by 2022), cost assumptions used for additional cleanup liability associated with an additional share of the plant, the revenue requirement generated for the company, and any comparisons made between an additional share in Colstrip and other energy and capacity options.

Response: This issue is discussed in Chapter 11.

Chapter 9

Comment:
NorthWestern should model compliance with the federal and state regional haze program. Other coal-fired power plants across the nation were required to install selective catalytic reduction technology to reduce nitrogen oxides in order to limit impacts to Class I airsheds. It is highly likely that should Colstrip continue to operate over the course of the next 20 years it will be required to install additional controls for nitrogen oxides. It would be reasonable to require such modeling in final plan because as the draft plan points out, it would “require material upgrades.” These costs should be considered in the final plan because they are reasonably foreseeable.

Response: This issue is discussed in Chapter 11.

Comment:
NorthWestern decision to ignore the costs associated with the cleanup of the ash ponds at Colstrip - estimated by other owners to be as much as $700,000,000 - is unreasonable and

untenable. These costs will be incurred regardless of whether some of those costs are attributable to compliance obligations under the federal coal combustion residual rule or the Administrative Order on Consent pursuant to Montana's Major Facility Siting Act. Clean-up of groundwater and surface impoundments due to Colstrip Units 3 and 4 ash ponds will be the most expensive area at the plant to remediate. It is negligent to ignore these costs, especially considering NorthWestern is not seeking reimbursement in its current rate case, leaving these exorbitant costs for future generations who will likely not utilize the resource. This would create major and inappropriate intergenerational inequity.

Response: This comment has no bearing on the 2019 Resource Plan.

Comment:
As previously noted, the final plan should take into account the ruling of the state district court in the QF-1 case (Docket D2016.5.39) and make any modifications necessary to match the requirements of that ruling, including regarding carbon costs and carbon avoidance values.

Response: This issue is discussed in Chapter 11.

Comment:
Chapter 9 does not seem to state what assumption was used for the amount of CO2 produced by different fossil fuel generating units, specifically gas units (i.e. Aero vs Rice vs combined cycle). While burning gas for electricity produces less CO2 than coal, it is not zero. The final plan should clarify what assumptions were used regarding how much CO2 would be produced from all fossil fuel burning technologies considered in the plan.

Response: This issue is discussed in Chapter 11.

Chapter 10

Comment:
The draft plan lacks documentation of the cost of existing resources as well as a comparison of those resources to other energy options. It is impossible for a ratepayer to conclude they are receiving least-cost energy if existing resources are not modeled for cost effectiveness compared to other options. Montana-Dakota Utilities (MDU) is conducting this kind of analysis for its customers. MDU President Nicole Kivisto was quoted in the Billings Gazette on May 1, 2019 stating the company compared its Lewis and Clark Station coal plant with other energy sources and found it would save ratepayers money to switch to another source. Said Kivisto: "We're comparing continuing to run these facilities with replacing them with another source. What we demonstrated is that it would be at half the cost to the customer."[3] NorthWestern

[3] https://billingsgazette.com/news/state-and-regional/govt-and-politics/regulators-concernedby-mdu-s-cost-saving-plan-to-shutter/article_6ce13808-4ba5-5a9a-8952-75333a3f288d.html

Enegy’s final plan should document the cost of existing resources and compare them to other energy options to ensure ratepayers are receiving least-cost energy.

Response: The fixed costs of existing resources have no bearing on the resource plan as PowerSimm dispatches existing resources based upon the variable costs of generation. If the variable costs of an existing resource increase, the unit could be dispatched less – which would be taken into account in PowerSimm.

Comment:
The draft plan makes the following assumptions when evaluating adding wind, solar, or battery energy storage:

- 210 MW of wind added in 2022.
- 210 MW of solar added in 2022.
- 105 MW of lithium ion batteries added in 2022.

It is unclear why 210 MW and 105 MW chosen for wind/solar and battery storage respectively. It is also unclear whether, given Table 7-6 and 7-7 notes cost assumptions for wind and solar facilities at 105 MW in size, and battery storage at 26 MW, the modeling assumed two separate wind and solar facilities would need to be built to reach 210 MW and four separate battery facilities to reach 105 MW. If two separate wind/solar and four separate battery storage facilities were assumed to be needed to be built to reach this self imposed 210 MW size limit, then the draft plan likely uses inaccurate cost projections for these technologies. Both wind and solar facilities are commonly larger than 100 MW in size, reducing their costs as economies of scale are accessed. It would be entirely reasonable for a single wind or solar facility to be 210 MW in size, thereby reducing the cost compared to two separate 105 MW facilities. Similarly, the size of lithium ion battery storage facilities has rapidly increased in recent years and a single project can now easily reach 105 MW in size. The final plan should model wind and solar facilities at larger than 105 MW in size and battery storage systems larger than 26 MW.

Response: This issue is discussed in Chapter 11.

Comment:
It is unclear why 2022 was the year wind, solar, and battery energy storage was evaluated for addition to the portfolio. It is also unclear whether these technologies were evaluated for addition to the portfolio in any year after 2022. The final plan should evaluate wind, solar, and battery storage for their potential to be a least-cost option in all years within the planning horizon, not just one.

Response: This issue is discussed in Chapter 11.

Comment:

Discussion of different resource addition scenarios on pages 10-11 and 10-12 notes, “After wind is added, additional resources were selected using constrained ARS analysis.” This is repeated with solar, pumped hydro, and lithium ion batteries where “additional resources” are apparently added to these scenarios as well as constraints being put on the modeling tool. However, “additional resources” are not described and neither are the ARS constraints used. Both of these inputs into a model could drastically change the outcome. For example, if 210 MW of wind was added but then a 350 MW combined cycle gas plant “additional resource” was also added, the cost of the wind addition becomes dramatically distorted. Similarly, the ARS constraints could be set in a manner either inappropriate or, at the least, different than constraints used in the rest of the modeling for the rest of the plan, greatly diminishing any apples-to-apples comparisons between resources. The final plan should make clear precisely what constraints are being used when modeling each resource, including wind, solar, and energy storage, and describe any other resources (including their cost assumptions) that are included with wind, solar, and energy storage expansion scenarios.

Response: This issue is discussed in Chapter 11.

Comment:
The discussion of carbon cost scenarios on page 10-12 similarly notes, “resources were added to the portfolio using constrained ARS analysis.” The final plan should explain what resources were added, the cost assumptions used for them, and the ARS constraints used in these scenarios.

Response: This issue is discussed in Chapter 11.

Comment:
It is unclear whether the future “low cost” curves for wind, solar, and battery energy storage systems found in Figure 7-2 were used at all in the modeling described in Chapter 10 or whether only the “regular” wind, solar, and battery storage costs from that figure were used. The cost differences vary greatly between these two cost curves for the year 2022, let alone years after. The final plan should model adding these resources in future years beyond just 2022 and using the “low cost” curves.

Response: This issue is discussed in Chapter 11.

Comment:
No scenario was modeled where wind or solar was paired with battery storage. No explanation is given for why this decision was made. Wind and solar paired with battery storage are now regular options for utilities. Projects of this nature are being proposed and completed around the country and around the world. Also, when a solar facility is paired with a battery energy storage facility it allows the entire facility to access the federal Investment Tax Credit (ITS),

thereby significantly changing the economics compared to solar and batteries being sited separately. The final plan should model wind and solar paired with battery storage as both energy and capacity options.

Response: This issue is discussed in Chapter 11.

Comment:
It is not persuasive to simply state the plan assumed NorthWestern will join a RTO in 2025 and therefore no other scenarios should be considered, such as evaluating wind, solar, or battery storage for cost effectiveness in all other years. As noted previously in these comments, there is massive uncertainty about any future RTO situation. Ratepayers will be put at risk of the company making bad decisions if the only scenario the final plan considers is one where NorthWestern joins some completely undefined RTO in 2025. The final plan should model scenarios different than this.

Response: This issue is discussed in Chapter 11.

Comment:
Page 10-14 states, “The ARS analysis in this Plan generally selects natural gas fired thermal generation.” However, Table 10-2 immediately above this statement makes it clear that the plan selected zero wind, solar, pumped hydro, or lithium ion batteries. That table also makes clear only gas units were selected. It is incorrect to say the plan “generally selects” gas units when it is clear the plan only selects gas units. The final plan should accurately describe its scenarios and outcomes.

Response: This issue is discussed in Chapter 11.

Comment:
Chapter 10 makes qualitative references to risk and “risk-adjusted NPV,” but does not describe the actual quantitative amounts assigned to these. The final plan should not lump this “risk” in with the cost of a resource without separately quantifying it and how it was calculated. It should instead clearly describe and quantify the “risk premium” assigned to each resource type and fully detail how they were calculated.

Response: The risk premium for each portfolio was separately quantified and is displayed in Figures 10-2, 10-3, 10-4, and 10-5. The description of how the risk premium is calculated for each portfolio is on Page 10-8 under the heading “Evaluating Risk Premium.” The risk premium is calculated as the difference between (a) the probability-weighted average of the estimated costs above the median cost and (b) the median cost.

Respectfully submitted,
Brian Fadie
Clean Energy Program Director
Montana Environmental Information Center
406-443-2520
bfadie@meic.org

Ben

“The following comments are not submitted on behalf of the Montana Public Service Commission. The Commission has not reviewed and does not necessarily endorse any of these comments. The Commission has retained a consulting firm to analyze and provide NorthWestern feedback on the draft plan. The brief comments below represent just a few general thoughts from myself and other staff members on the draft plan.

The chapter on NorthWestern’s Electric Transmission System – Chapter 6 – is confusing and needs further explanation. The numbers within the chapter do not always seem to add up. For example, Figure 6-1 indicates Path 6 has 1,350 MW import capacity on the line, but, on the following page, Table 6-1 indicates long-term total transmission capacity on Path 6 to be 1,245 MW.

Response: NorthWestern is assuming that the Path 6 reference in the question is supposed to be Path 8. The variance you describe is the result of seasonal reductions to the Path. Figure 6-1 displays the maximum import capacity of Path 8, which is 1,350 MW. Table 6-1 is used to estimate available Long Term Firm capacity that customers can reserve to serve their load. In order to estimate this capacity, the most restrictive seasonal availability is used. The maximum total transfer capability for Path 8 is 1,350 MW, and the minimum total transfer capability is 1,245 MW, as a result of seasonal limitation of Path 8 import capability identified in reliability study work.

NorthWestern could do a better job of explaining what entities are using capacity on each of the transmission Paths delivering power in and out of Montana, how long each of those entities are expected to hold transmission capacity rights, and to what extent transmission capacity on each of the transmission Paths might become available.

Response: NorthWestern has updated Chapter 6 to include a discussion of the customers’ using the remaining short term capacity to serve load.

There should also be more explanation in the chapter with respect to who is utilizing capacity on each of the transmission Paths during the example days provided in Figures 6-2, 6-3, and 6-4. For example, during each of the example days provided, what entities were utilizing transmission capacity on the BPAT line when it has zero capacity, what entities were scheduling import capacity on each of the other transmission lines, and how much import capacity was available on each of the other transmission lines and at what cost. There should also be more discussion with respect to the general cost and congestion issues associated with the transmission Paths other than Path 8 that render the transmission Paths unreliable or uneconomic as far as meeting future load obligations.

Response: NorthWestern has provided additional data for each of the three days listed in Chapter 6 describing who is using capacity on the BPAT path.

Finally, the chapter should explore potential transmission-related solutions for NorthWestern to meet peak loads in the future. In general, the issues raised in Chapter 6 need to be better explained and the plan should do a better job of exploring transmission-related solutions to meeting future load obligations.

Response: NorthWestern is concerned about the ability to meet its retail and 3rd party network loads. As the ESRP discussed, NorthWestern's energy supply function is significantly deficit capacity to serve its retail load. In addition to that concern, there is not currently a plan that NorthWestern is aware of, to serve third party network load requirements. We have begun to see a shift to added long-term import of power and long-term transmission reservations from BPA. We expect this practice to increase with the recent announcement of the closure of Colstrip Units 1 and 2. This practice could cause a shortage of transmission capacity to import power from BPA which has NorthWestern concerned from a reliability standpoint.

In fact, NorthWestern has experienced instances in which suppliers have not successfully scheduled replacement import power following a transmission curtailment in a system adjacent to NorthWestern, again causing potential reliability concerns

The draft plan does not do a good job of discussing rate impacts associated with each portfolio considered or potential rate designs that may be utilized to achieve public policy goals. The administrative rules of Montana under which NorthWestern operates require NorthWestern to consider rate design and rate impacts in its long-term resource procurement plan. See Admin. R. Mont. 38.5.8210(3), 38.5.8211, and 38.5.8213(1)(b). The final draft of the plan should do a better job of addressing rate impacts associated with resource procurement, and potential rate designs that promote the utility's financial health while simultaneously achieving public policy goals (such as economic efficiency and environmental responsibility).

Response: This issue is addressed in Chapter 12, which has been added to the Plan.

On an April 24 conference call with financial analysts, NorthWestern CEO Bob Rowe described failed Senate Bill 331 as a "missed opportunity" to acquire an additional share of Colstrip, in part, because the resource would provide "great immediate and long-term value for [NorthWestern's] customers, a great bridge resource." NorthWestern was also active in lobbying at the 2019 Montana Legislature to advocate for the benefits of acquiring additional shares of Colstrip. If Colstrip is a resource that is available for purchase and NorthWestern believes that Colstrip could provide value to customers, then the final draft of the procurement plan should provide discussion and analysis regarding the costs and benefits associated with an additional share of Colstrip."

Response: This issue is addressed in Chapter 11, Response to Public Comments.

MONTANA RENEWABLE ENERGY ASSOCIATION
P.O. Box 673
Missoula, MT 59806
(406) 214-9405
www.montanarenewables.org

May 5, 2019

To: John Bushnell, Manager, Energy Supply Planning & Regulatory
NorthWestern Energy 208 N. Montana Ave.
Helena, MT 59601

Re: NorthWestern Energy's Draft 2019 Electricity Supply Resource Procurement Plan

Dear Mr. Bushnell,

Thank you for the opportunity to comment on NorthWestern Energy's Electric Supply Resource Procurement Plan ("Plan"). MREA feels this is an important element of stakeholder input and transparency. We have stated before, and will reiterate, that we feel this type of opportunity is important to further transparency in the planning process. On page 1-14 of the Plan (and again later), NWE states it is considering whether or not to maintain the Electric Technical Advisory Committee (ETAC) as a means of incorporating public comment. MREA supports the continued use of ETAC, and suggests further opening the process to be more transparent and to ensure that stakeholders that do not currently have a seat on ETAC are able to attend meetings and provide input into discussions relevant to their expertise and/or constituencies.

Below are MREA's specific comments.

1. Page 1-13. NWE states that portfolio modeling shows that natural gas resources provide the lowest cost portfolio. The Plan should discuss whether current natural gas prices or average prices were used in modeling. Natural gas prices are low compared to the past two decades. The final Plan should model scenarios in which the cost of natural gas increases in the coming years.

   Response: This issue is addressed in Chapter 11, Response to Public Comments.

2. Page 2-11. The Plan states that there are barriers to acquisition of higher levels of demand response. The final Plan should discuss what those barriers are and how NWE may be able to address them.

   Response: 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 to complete this work, which is expected to be finalized in 2019. The results of these activities may result in adjustments to the forecasts noted in this plan.

3. Pages 2-14 and Figure 2-2. The Plan discusses the alignment between NWE and the NWPCC's winter peaks. The Plan should address how NWE investigated alignment with summer peaks, as NWE's summer peaks appear to be as high as, if not greater than, the winter peaks.
   Response: NorthWestern did not investigate summer peaks as summer peak loads do not represent our critical peak load period.

4. Figure 3-1 (page 3-3). The final Plan should explain why the retail load *with* DSM and *with* DSM + NEM trends *higher* than retail loads without them. It seems like it should be the opposite.

   Response: The Retail Load shown in the graphic is net of DSM savings and NEM production. The figure is correct.

5. On Page 3-7 the Plan refers to INC and DEC resources. These are defined later in the Plan (specifically on page 4-3). For readability and clarity, these terms should be defined here, before being used.

   Response: A footnote has been added to page 3-7.

6. Page 3-8. The Plan notes that the modeling placed solar and wind resources in various places around the state. The final Plan should address what criteria the model uses for locating these resources. Specifically, it would be helpful to note if the criteria include solar irradiance and wind speed values at hub-height, in order to maximize production from those sites.

   Response: The Plan does not provide a path for resource acquisition. Rather, the Plan discusses NorthWestern's reliance upon competitive solicitations to acquire resources. Developers bidding in to a solicitation will, hopefully, take these considerations into account when preparing their bids.

7. Page 3-12. The Plan states that the utility "has no need for resources that produce energy during LL hours." The final Plan should address how the utility avoids using resources to produce energy when low load is required.

8. Page 3-12. "The Plan states that must-take resources that are not dispatchable, like wind…" The final plan should aid readers by describing what is meant by "must-take."

   Response to 7 and 8: "Must-take" means that NorthWestern must take whatever level of electricity production is generated. Must-take resources are non-dispatchable or have limited dispatchability; and include minimum turndowns for thermal resources, must-take from PURPA resources, and hydro operation constraints.

9. Figure 3-2 (page 3-13). The final Plan should provide more details to help readers understand this figure.

Specifically, the Plan should describe what resources are include in the "Tier II Thermal" and "RFP/PPA Morgan, PPL, Transalta" categories.

Response: RFP and PPA are defined in the Plan and the Glossary and in the Definitions. Morgan, PPL and TransAlta are the counter-parties to these agreements. As can be seen in the figure, these PPAs play no role in NorthWestern's future resource portfolio.

Page 4-1. The final Plan should address at what penetration level would the utility consider 1) distributed generation and b) DSM as a supply-side resource. It should discuss whether or not the utility would ever consider them as a supply-side resource or if they would be kept separate, and for what reasons.

Response: DSM is already considered as a supply-side resource and is acquired first. NorthWestern includes Universal System Benefits (USB) renewable energy projects as part of the overall DSM acquisition. Distributed generation is included in evaluation of cost effective DSM.

10. Page 4-1. The final Plan should address how having an MPSC ordered rate does or does not guarantee that a resource will come online. The Plan could specifically use the MTSun project as an example.

    Response: The MTSUN project is still relevant and the Commission's order is under legal review.

11. Table 4-1. In the table, the MTSun project is estimated to expire on 1/1/2030. The final Plan should note why this expiration date is so much shorter than other QF's, especially the other solar QFs, in the table.

    Response: MTSUN is a 15-year contract so the expiration date is valid. The discussion has not been changed.

12. Page 4-8. The Plan discusses "significant additions of qualifying facilities" while noting that NWE's average retail load is "<u>only</u> 747 MW" (emphasis added). Earlier, the Plan notes that there is an important difference between nameplate capacity and actual energy contribution (see Figures 4-2 and 4-3). The framing of this section on Page 4-8 is misleading and implies an overabundance of QF development that will provide unnecessary energy. For readability and consistency, the final Plan should allow the data provided in the paragraph to speak for itself.

    Response: The discussion is valid and has not been changed.

13. Figure 4-6, page 4-10 (and other sections through the document as well). The Plan focuses heavily on the winter peak loads. Table 3-3 (page 3-6) shows the actual summer peak is forecast begin to eclipse the actual winter peak in 2028. Further, the historic values in that same column in Table 3-3 show actual summer peaks eclipsed winter peaks just as often as winter peaks eclipsed summer peaks. The final Plan should address whether or not the same modeling shown in Figure 4-6 has been conducted to address summer peaks, and if not explain why.

Response: The Summer peak forecast does not exceed the winter peak forecast.

14. Figure 4-7, page 4-11. The figure notes this is "Hour 17" but does not note the day and month. The final Plan should provide the day and month of the demonstrated peak for context.

    Response: The day was July 17th, but point of the figure is to show what the capacity deficit (547 MW) was on that day. The total (measurable) solar production available to the portfolio was 8 MW installed capacity. Given the low amount of solar PV, solar generation would not show in the figure, so rather than have it appear that solar didn't generate any electricity, we excluded it from the figure. The figure has not been changed.

15. Figure 4-7, page 4-11. The final Plan should explain why solar energy is not included in this Figure. Neither the figure nor narrative explain why, and it is unclear if solar was not-producing at this hour (and had a 0 value) or if solar was excluded from the figure (had a non-zero value but was not included).

    Response: Our solar PV resources would not show up in the figure, so rather than have it appear that solar didn't generate any electricity, we excluded it from the figure.

16. Figure 4-7, page 4-11. The labels used as part of this graph are inconsistent (in color and descriptor) with other figures in the document that demonstrate similar information. This could cause confusion among readers. It would be helpful if the final Plan had the color and descriptors consistent for similar graphs like these throughout the document.

    Response: The table has not been changed.

17. Figure 4-7 and Table 4-2 (page 4-11). Several of the descriptors note "(No Wind)". The final Plan should provide a footnote or narrative to explain what this means.

    Response: The reference is meant to be self-explanatory' "no wind" is included in those categories.

18. Page 4-12. The Plan states that QF projects providing DEC "require compensation that would reflect no monetary loss." The final Plan should discuss the scale on which QF may or may not experience monetary losses – e.g. monthly, or on a per kWh/MWh basis, etc.

Response: Compensation would vary from QF to QF and would be subject to individually negotiated terms of the contract, or amendment to the contract.

19. Table 4-4, Page 4-13. The final Plan should explain why only two of the hydro projects are able to provide DEC.

    Response: Those are the only hydro projects currently capable of providing DEC.

20. Table 4-5, page 4-15. This table is not introduced or explained. It would be helpful if the final Plan included a brief narrative explaining the table in context, including the implications of "$/aMW Acquired".

    Response: Chapter 4 and Table 4.5 has been updated.

21. Table 4-5, page 4-15. The Cumulative value for the third column ($/aMW Acquired) appears that it isn't a cumulative value. Should this be the sum of the values above it, or are there other implications to this value? If there are other implications, the final Plan should address those.

    Response: Chapter 4 and Table 4.5 has been updated.

22. Table 4-8, page 4-23. The Plan (based on Navigant's NEM study) assumes that in the "Low" scenario, there would be 16MW of aggregate NEM capacity installed on NWE's system by 2018. Now that 2018 has ended, the final Plan should note that the actual total of aggregate NEM capacity installed on NWE's system as of the end of 2018. If the total aggregate capacity at the end of 2018 is not consistent with the estimates used in the Navigant study, the final Plan should discuss how NWE plans to address this inconsistency, and specifically how this may change the forecasted adoption scenarios for NEM.

    Response: NEM will not be updated until the next resource planning cycle.

23. The Navigant NEM study focused solely on residential NEM systems. The final Plan should discuss whether non-residential installations were also considered and/or used in any modeling. If non-residential NEM was considered in the Plan, the final Plan should discuss how they were valued compared to residential systems.
    Page 4-26, discusses the CREP requirement. The final Plan should provide more context into the utilities compliance with the CREP requirement. This should include the reasons that the CREP projects did not qualify or otherwise meet the MCA rules, and a discussion of when the utility was last in compliance with the CREP requirement.

    Response: Please see NorthWestern's CREP discussion in its annually filed 10K report, on page 12:

http://www.northwesternenergy.com/docs/default-source/documents/investor/2018_annualreport.pdf

Page 5-6. The Plan notes, "The study results indicated that annual benefits for NorthWestern would range from $1.4 million to $3.0 million, which a base case of $1.8 million." It is unclear which scenarios were which. The final Plan should provide a table comparing the results.

Response: The low end of the range represents the case of a wider EIM footprint. The high end of the range represents the high renewables case. The full E3 EIM report will be provided in Volume 2.

24. Page 6-6. The Plan notes "The total executed [PPA's] is equivalent to about 125 percent of NorthWestern's retail supply minimum load of 443 MW." Earlier in the Plan, the authors note that there is an important difference between nameplate capacity and actual energy contribution (see Figures 4-2 and 4-3). Suggesting an overabundance of development is misleading as to the actual contribution of energy to meet load.

    Response: These figures are correct and the comparison is valid.

25. Figures 6-2, 6-3, 6-4 (page 6-10 through 6-13). The Balance Authority Needs by Hour graphs include a comparison of Colstrip production as well as wind production during those times. The Plan should explain why other owned and/or contracted resources not included in these graphs.

    Response: The figure was designed to show the difference between dispatchable resources and non-dispatchable resources. Other resources were not included to keep the graph clean. NorthWestern has added Tables showing the amounts of capacity reserved to import energy during these times.

26. Page 6-16 to Page 6-17. The Plan discusses key takeaways from the discussion of loads and the availability of market resources during the spring and summer of 2018. Other energy sources, such as solar and natural gas, seem to be missing. The final Plan should explain why these were not included in his portion of the analysis.

    Response: Although not shown, these resources were key considerations in this discussion of transmission reliability. The natural gas facilities on NorthWestern's system are dispatchable resources. Total solar capacity on the NorthWestern system is equal to approximately 17 MW and didn't have a significant impact in the transmission analysis.

27. Chapter 7. The plan should discuss how specific capacity values were chosen when modeling resources (Ex: 100 MW of solar, 25 MW/100MWh BESS, 50MW RICE addition at DGGS). The plan should discuss if multiple sizes/capacity values were considered, and further if they were modeled or if multiple scenarios were modeled. The final Plan should also discuss whether the modeling *only* considered additions of that size, or if marginal contributions were also considered.

Response: Capacity contributions are consistent with those shown for existing resources and past Commission orders. Multiple scenarios were not modeled and marginal contributions were not considered.

28. Figure 7-2, page 7-24. The final Plan should provide context and a narrative explaining this figure. Historically, the cost of wind and solar development have continued to decline, yet this figure demonstrates the opposite. In addition, the final Plan should discuss the differences between a technology and the related "low-cost" version listed on the graph (e.g. "Solar PV" versus "Low-Cost Solar PV", "Wind" and "Low-Cost Wind", and "Li-ION" vs "Low-Cost Lithium Ion").

    Response: The discussion in Chapter 7 has been updated to reflect how the low cost futures for wind, solar PV and Li-Ion were included in ARS.

1. Page 8-3. The Plan mentions connecting certain DER's to the ADMS software and network. The final Plan should provide an explanation of the implications and capabilities of doing so. For example, how would this affect owners of distributed generation systems? How would it impact their ability to use onsite energy? What are the grid impacts? How would NWE use this module? Would NWE control the output of the distributed generation systems? Would NWE control the amount of energy exported from the distributed generation systems?

    Response: Response: In those instances where NorthWestern had a contractual arrangement to control a customer owned DER, such as energy storage or an onsite generator, NorthWestern could use such a system to call on this resource to supply power for a time. The contractual arrangement would specify the terms of use and compensation. NorthWestern would control the output of the DER by setting the real and reactive power parameters and the duration. In some cases using the DER may affect the customer's ability to utilize the resource later in the day. For example, battery storage may be depleted and need to wait for a recharge cycle prior to being available for the customer's use. Regarding the grid NorthWestern would use these resources in a number of ways, such as to support capacity or voltage during peak times, or during system disturbances. In some cases the DER may be able to "black start" an area, and provide power to an island during an outage. Customer owned back up generation would have this, but unless it was sized large enough to carry the customer load plus some additional utility load it may not have much value to the grid as an islanding resource.

29. Table 8-1, page 8-5. The final Plan should define what is suggested by a "smart inverter" as well as an "advanced inverter". This should include what the utility considers as the differences between the two. If referring to specific functionality of the inverter, the Plan should note and discuss those to provide context.

    Response: The terms are used interchangeably in this document and should have been rendered as one or the other. An advanced inverter is one where the real and reactive power flow can be controlled across a range and that control can be accomplished remotely. Therefore an advanced inverter could be controlled similar to a DER via the ADMS system together with additional software. By controlling reactive power at an inverter much needed voltage support can be provided to the electric system, thereby allowing for additional capacity during peak times or system disturbances.

2. Page 10-3. The Plan notes that "Resource additions were limited to about 200 MW per year." The plan should note if this is nameplate capacity, or if this is based on forecasted energy generation and contribution. The Plan discusses the important difference between nameplate capacity and actual energy contributions. Basing this on nameplate capacity may negatively bias against certain resources, (e.g. large wind generation development).

   Response: The 200 MW per year is peaking capability. The peaking capability of wind (capacity contribution to peak) is five percent of nameplate capacity.

3. Page 10-10 (and Table 10-1). The plan should explicitly note and describe the resources included in the "Current" portfolio. It is not clear if this portfolio includes all of the utility's currently owned and contracted supply resources, including coal, hydro, wind, solar, natural gas, etc.

   Response: See Chapter 11 of Volume 2 for tables showing resources additions by portfolio and year.

4. Page 10-16. The Plan notes "pumped hydro doesn't provide for customer's needs." The final Plan should explain this contention further.

   Response: The reference needs no further explanation. If pumped-hydro did provide for customer needs it would have been selected in the unconstrained ARS. That said, we look forward to future RFPs when we will we be able to evaluate real resources, not the generic resources evaluated in the Plan.

5. Table 10-4 (page 10-19). The Table does not include solar. The final Plan should address why solar been excluded from consideration.

   Response: This is because Table 10-4 shows the resources selected in various portfolios. ARS selected wind resources over solar PV in all model runs. Also see Chapter 11.

6. Page 10-20. The Plan notes that, "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 final Plan should explain whether other resources, including thermal resources, would require upgrades and/or additions to the electric transmission system in the same manner.

   Response: This issue is addressed in Chapter 11.

7. Page 11-4. The Plan lists certain resources that NWE would consider through an RFP process. It lists solar + storage as well as wind + storage. The final Plan should address if the utility will consider solar and wind development if storage is not paired. If not, it should address why.

   Response: Yes, but those resources are not listed because NorthWestern does not anticipate that those resources would be economically viable in a solicitation seeking resources to meet peak loads.

Thank you again for the opportunity to comment on the draft of the Plan. We look forward to seeing the responses to these and other comments/questions in the final version.

Gratefully,

Andrew J. Valainis
Executive Director

TO: NorthWestern Energy, Montana Public Service Commission

FROM: Natural Resources Defense Council (by Chuck Magraw)

DATE: May 6, 2019

SUBJECT: NorthWestern Energy 2019 Electricity Supply Resource Procurement Plan (N2018.11.78)

The Natural Resources Defense Council (NRDC) submits the following comments on the NorthWestern Energy (NWE) draft 2019 electricity supply resource procurement plan.

It is an entirely legitimate question, as a result of its treatment of Colstrip unit 4, whether the draft plan provides anything in the way of value in terms of assisting NWE, the Commission, and stakeholders in assessing the utility's future procurement needs.

NWE's procurement plans are developed in order for the utility to take a long range view of its suite of existing resources and to consider additional supply needs in light of the utility's future load requirements, conditions in the industry, and societal trends; in other words, basically any and all factors that have a bearing on decisions that will need to be made to ensure that the utility has the resources that will best serve its customers. Such an analysis, obviously, requires a consideration of costs and risks.

The draft plan falls far short of achieving these objectives because it chose to ignore Colstrip. In the development of the plan NWE planners made it clear that issues related to Colstrip and its long-term viability were not going to be addressed. The ostensible, and oft-provided, reason for this was that since unit 4's closure was not anticipated any discussion (or planning for) its closure was premature. That explanation, however, is flatly at odds with sound energy planning.

It should go without saying that Colstrip's long-term future is highly uncertain. A recitation of the hurdles faced by that facility would serve little purpose here. Suffice it to say that there is significant pressure on the west coast Colstrip co-owners to extricate themselves from Colstrip generation. The most recent example of this is the passage in Washington of SB 5116,[1] which requires that Washington utilities eliminate coal-based generation from their portfolios by the end of 2025.

Presently, Colstrip unit 4 supplies NWE with approximately 20% of its energy supply needs. Its importance to the portfolio, combined with the <u>risk</u> that it will cease generating in the not so distant future, suggest that a plan for future resource needs should take a serious look at the resource's role in the portfolio, what its absence would mean, and how to replace that resource. Yet the draft plan blithely assumes that the unit will operate throughout the planning period.

In short, the failure of the draft plan to consider a future without Colstrip is a missed opportunity and renders the plan of limited to no value.

Response: Thank you for your comments. This issue is addressed in Chapter 11, Response to Public Comments.

[1] http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Senate%20Passed%20Legislature/5116-S2.PL.pdf#page=1

NORTHWESTERN ENERGY DRAFT 2019 RESOURCE PROCUREMENT PLAN
COMMENTS OF THE NW ENERGY COALITION

The NW Energy Coalition appreciates the opportunity to provide the following comments on NorthWestern Energy's draft resource procurement plan. As a member of the Electricity Technical Advisory Committee, we appreciate NorthWestern's commitment to improve the planning process as compared to the 2015 planning period; however, we look forward to working with NorthWestern to continue improving this increasingly vital process, especially considering the "evolving" energy landscape.

1) The Technical Advisory Committee process is important.
As such, we find the statement "NorthWestern is considering whether maintaining the technical advisory committee is the best means of incorporating the public into the planning process" to be concerning and reactionary. Should NorthWestern wish to keep this sentiment in this important planning document, the utility should expand upon this statement and provide alternatives for stakeholders to also consider. Every major investor owned utility in the region undertakes a comprehensive and technical stakeholder IRP process. NorthWestern should not stray from incorporating important feedback throughout the process. If anything, NorthWestern should make the process more robust and seek further advice from underrepresented communities.

Response: The ETAC is discussed in Chapter 11 and Chapter 13.

2) The draft plan relies exclusively on supply resources and mistreats and ignores demand-side resources

NorthWestern has identified a large capacity deficit over the last two planning processes. However, though encouraged by stakeholders and the Coalition, the 2019 plan does not expand the ability for demand-side resources to meet this capacity need. Energy efficiency is the cheapest, cleanest, and most readily available energy resource; yet, NorthWestern has decreased its reliance on the resource since the 2015 plan. Montana Code Annotated 69-8-419 states that the utility *shall* "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." This has not been accomplished in the draft plan, leading, in part, to NorthWestern's capacity need.

a. Calculation of DSM cost-effectiveness in incomplete and incorrect. NorthWestern's claims to use the Total Resource Cost test but fails to include many elements of the test. The test used by NorthWestern is not the TRC. NorthWestern also does not apply a 10% adder to energy efficiency, ignoring the NorthWest Power Act of 1980.

Response: NorthWestern entered into a stipulation with the Northwest Energy Coalition in the Electric Rate Review, Docket No. D2018.2.12, where if approved by the Montana Public Service Commission, this and other items included in the stipulation will be considered.

b. NorthWestern notes in chapter 6 that Transmission is becoming increasingly valuable to its system, in large part due to the limited ability to import energy. The Coalition agrees, and believes this added benefit should be included in DSM cost-effectiveness calculations.

Response:
NorthWestern entered into a stipulation with the Northwest Energy Coalition in the Electric Rate Review, Docket No. D2018.2.12, where if approved by the Montana Public Service Commission, this and other items included in the stipulation will be considered.

c. NorthWestern provides a defacto 0% capacity value to DSM. NorthWestern applies a capacity value to every resource except DSM, undercutting the value this important resource provides. We understand that NorthWestern has contracted with Nexant to include capacity values. These should be included in the final plan.

Response:
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 to complete this work, which is expected to be finalized in 2019. The results of these activities may result in adjustments to the forecasts noted in this plan.

d. DSM should be treated like any other supply resource. There is no need to decide cost-effectiveness based on avoided cost for DSM planning purposes, only for selection and implementation of individual measures and programs. No other supply resource undergoes Total Resource Cost valuation (except that capacity values are included for other resources); rather the estimated cost of the resource are input into the model and selected on a pure cost basis. This is more akin to the Utility Cost Test, though in this instance the model uses solely Utility Costs, not the entirety of the test. While DSM measures are abundant, technically achievable measures can be bundled based on cost (only administrative and incentive costs should be included). The model would then select bundles that are cheaper than new build.

Response: NorthWestern entered into a stipulation with the Northwest Energy Coalition in the Electric Rate Review, Docket No. D2018.2.12, where if approved by the Montana Public Service Commission, this and other items included in the stipulation will be considered.

e. Demand response has once again been ignored. The Demand Response report in the 2015 Plan identified 35 MW of nominated demand response capacity by commercial customers. Despite repeated statements that further DR investigation would be included in the plan, NorthWestern has indicated no steps have been taken, instead relying on tired language from previous plans and previous perfunctory actions. NorthWestern should further discuss its plans for the future for demand-side resources, rather than what is has (or has not) done in the past.

   Response: NorthWestern's chapter on portfolio additions action plan items specifically mentions demand response as a potential resource an eligible resource in future RFPs. Additionally, NorthWestern plans to pursue DR outside of the RFP process. An action plan item has been added to the plan.

f. Perhaps indicative on NorthWestern's view of demand-side resources, there are no Action Plan Items on the topic.

   Response: An action plan item has been added to the plan

3) <u>Planning for 16% reserve margins is unwarranted at this time.</u>

NorthWestern's draft plan seeks to incorporate resources to fill peak capacity need plus a 16% reserve margin. Figure 2-1 on page 2-13 indicates that this would be the one of the largest planning reserve margins in the northwest, exceeding much large utilities including Idaho Power, Rocky Mountain Power, and Puget Sound Energy. Given that the Commission has yet to provide strong support of a plan seeking to reach procurement of 100% peak capacity, much less a 16% reserve margin, it seems prudent to plan for the former rather than the latter at this time. The plan also gives no indication why a planning reserve is needed, nor why 16% is an appropriate target, outside of a footnote to Figure 2-1. Alternatively, NorthWestern could highlight scenarios including various percentages of planning reserves.

Response: While this issue is discussed in Chapter 11, this graph is intended to show the extent to which our Pacific Northwest peers have attained this 16% reserve margin, and the extent to which the customers of these utilities are exposed to the market to meet peak needs.

4) Include both retirements and new build.

NorthWestern states that reliance on the market is not prudent given the current load of the region and the planned retirements of 3,600 MW in the Northwest. This is only one side of the coin. To fully analyze what the regional energy outlook will entail, NorthWestern should also include plans for new build by other northwest utilities. During the last planning cycle, it was noted by the Coalition that utilities in the northwest region had IRPs containing 6 gigawatts of new gas build.

Response: This issue is discussed in Chapter 11.

5) The draft plan ignores risks related to the Colstrip Generating Station

The draft plan details environmental risks related to continued operation of the Colstrip Generating Station. The plan does not, however, discuss economic risks or risk of early closure of the beleaguered coal plant. MCA 69-8-419 states the utility *shall* "identify and cost-effectively manage and mitigate risks related to its obligation to provide electricity supply service." NorthWestern must agree there exists at least a risk of complete closure of the Colstrip Generating Station within the planning horizon. In fact, NorthWestern's depreciated date of 2042 is just outside a 20 year timeframe. Many utilities in the NorthWest are actively planning coal plant closure; ignoring the risk of early closure does NorthWestern's customers a disservice. NorthWestern should include in the final plan a scenario or portfolio including Colstrip retirement no later than 2030.

Response: This issue is discussed in Chapter 11.

6) The natural gas transmission discussion seems incomplete

Given NorthWestern's indication that it prefers the attributes of natural gas generation, the discussion of NorthWestern's natural gas system seems incomplete. If natural gas is to provide electric peaking capacity, several questions must be answered?

a. Does NorthWestern need new gas transmission to serve new gas plants? Were transmission upgrades or new transmission costs included in the costs input to the model?
b. Where does NorthWestern have gas transmission capacity to serve new gas plants?
c. The plan states on Page 6-19, "Currently, gas-fired generation on the system operates utilizing interruptible gas transportation arrangements. As a result, during the coldest days of the year, gas to supply to electric generation is subject to curtailment." Though non-chalantly stated, interrupted gas service to electric generation during the coldest days (i.e. peak needs) seems to

undercut the entire value of the resource. Did NorthWestern reduce the capacity value to address this risk?

Response: This issue is discussed in Chapter 11.

7) <u>Need to update discussion regarding carbon costs.</u>

The recent court ruling invalidating the Commissions exclusion of carbon costs should be updated in the plan. Consequently, a carbon cost should indeed be used in the base case in the final 2019 plan.

Response: This issue is discussed in Chapter 11.

<u>8) NorthWestern should be cautious about cherry-picking quotes and citing them out of context.</u>

Page 3-11 quotes an article in the Energy Activist by the NW Energy Coalition, my organization, dated July 27, 2018. The quote appears to attempt to justify NorthWestern's plan to acquire natural gas resources. Yet, the quote was unprofessionally taken out of context and should either be removed from the final plan, or the entirety of the quote included.

Note: the very next sentence after the quoted text states, "This week's price shock is a reminder that this isn't just an out-years game. Things are changing fast. We need to reduce reliance on natural-gas fired power for grid reliability and we need to speed the uptake of flexible demand - energy efficiency, storage, and demand response."

Since NorthWestern was enamored enough with the article to quote it, we encourage the utility to heed its findings rather than citing it out context. Unfortunately, the draft plan does nothing of the sort (see comment #2).

Thank you for the opportunity to comment on the draft plan. We hope NorthWestern will pay closer attention to the role that demand-side options can play in meeting its capacity needs. Doing so could provide customers with cleaner energy at cheaper costs.

Response: Thank you for your feedback.

Diego Rivas
Senior Policy Associate
NW Energy Coalition

Renewable Northwest
421 SW 6th Ave Ste 975
Portland, OR 97204
503.223.4544
RenewableNW.org

May 3, 2019

John Bushnell
Manager, Energy Supply Planning & Regulatory
208 N. Montana Ave., Suite 205 I Helena, MT 59601

Re: NorthWestern Energy's Draft 2019 Electricity Supply Resource Procurement Plan

Dear Mr. Bushnell,

Renewable Northwest appreciates the opportunity to submit these informal comments on NorthWestern Energy's ("NorthWestern's") Draft 2019 Electricity Supply Resource Procurement Plan ("ESRPP") prior to NorthWestern's formal submission of its ESRPP to the Montana Public Service Commission ("PSC").

I. INTRODUCTION

Northwestern's Draft ESRPP identifies a 725 MW need for flexible capacity based on a number of factors including regional retirements and NorthWestern's pending admission to the western Energy Imbalance Market ("EIM").[1] Renewable Northwest appreciates the challenges and opportunities these factors pose, as well as NorthWestern's commitment to a technology-neutral competitive solicitation process.[2] Nevertheless, we are concerned that several elements of the Draft ESRPP present significant risks that NorthWestern will not meet its resource needs with an optimal solution at the lowest long-term cost.

Montana law requires electric utilities to "plan for future electricity supply resource needs," guided by standards of "provid[ing] adequate and reliable … service at the lowest long-term total cost; … evaluat[ing] the full range of cost-effective electricity supply and demand-side management options; identify[ing] and cost-effectively manag[ing] and mitigat[ing] risks; … and provid[ing] … services at just and reasonable rates."[3] The Montana Public Services

[1] *Draft ESRPP*, Chapter 1.
[2] *Id.* at 11-3 to 11-4.
[3] MCA 69-8-419(1) & (2).

Commission has adopted rules to guide utilities in conducting resource planning processes.[4] These rules "describe a process framework for considering resource needs and suggest optimal ways of meeting those needs,"[5] consistently relating back to the statutory standards of providing "adequate and reliable" service at the "lowest long-term total cost."[6] In the end, a utility resource plan "must demonstrate … achievement of the objectives provided in 69-8-419 and compliance with commission rules."[7]

In these comments, we identify three substantive concerns and one procedural concern with the Draft ESRPP that, if un-addressed in the formally filed ESRPP, could fall short of Montana's regulatory standards:

- First, we compare the Draft ESRPP's assumed costs for solar, storage, and renewables plus-storage against several market indicators and draw the conclusion that the Draft ESRPP's assumed costs for these resources appear to be significantly above-market
- Second, we assess the Draft ESRPP's identified risk premium for gas-fired thermal resources against other recent decisions by utilities and regulators nationwide and question whether the Draft ESRPP accurately captures the full suite of risks associated with gas generation.
- Third, we note that the Draft ESRPP's identification of thermal resources as a focus of its procurement processes is out of line with other utilities' decisions nationwide, and we suggest that the Draft ESRPP's outlier status could be a result of the cost and risk assumptions we question in the first two sections of our comments.
- Then fourth and finally, we express our appreciation for NorthWestern's responses to our requests for technical information between the release of the Draft ESRPP and this informal comment deadline, but we note that additional technical information will be necessary for stakeholders to provide constructive comments that could support NorthWestern or help ensure that the Final ESRPP represents an optimal solution to NorthWestern's resource needs at the lowest long-term total cost.

We may consider addressing additional issues in future comments, including the intersection between regional retirements, NorthWestern's pending participation in the Energy Imbalance Market, and NorthWestern's identified resource need, as well as the capabilities and viability of the Colstrip Transmission System as it relates to potential transmission constraints.

[4] ARM Subchapter 38.5.82.
[5] ARM 38.5.8201(2).
[6] ARM 38.5.8203(1)(a) & 38.5.8204(1)(a).
[7] MCA 69-8-420(2).

II. COMMENTS

1. The Draft ESRPP's Cost Assumptions for Solar, Storage, and Renewables-Plus-Storage Appear To Be Significantly Above-Market

a. Recent Solar Cost Figures Significantly Undercut The Draft ESRPP's Assumptions

While the Draft ESRPP estimates solar costs at between $1,330/kW (prior to implementation of a federal tariff) and $1,430/kW (after tariff implementation) based on a single-axis tracking utility-scale system, current indicators of solar costs come in considerably lower. The most recent version of Lazard's Levelized Cost of Energy Analysis, for example, estimates a range of $950-$1,250/kW for utility-scale solar PV.[8] Idaho Power announced on March 26, 2019 that it had entered into a power purchase agreement ("PPA") for solar at a year-one rate of $21.75/MWh.[9] Looking conservatively at the deal — using Idaho Power's reported 20-year levelized price of $25.83/MWh for the full 220 MW of the PPA[10][11] and assuming a 15% capacity factor — one can extrapolate costs of approximately $678.81/kW.[11] That figure is about half of NorthWestern's assumed capital cost figure of $1,330/kW (sans tariff), which appears to be based on redacted values from an HDR study.[12] And Idaho Power's announcement came on the heels of a June 2018 filing by Nevada's NVEnergy seeking Public Utilities Commission approval of 1,001 MW of new renewables and 100 MWh of battery storage; 250 MW of that total came in the form of a power purchase agreement ("PPA") for solar at a year-one rate of $21.55/MWh.[13]

[8] *Lazard's Levelized Cost of Energy Analysis—Version 12.0* at 10 (Nov. 2018), *available at* https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.
[9] Idaho Power, *Press Release: Idaho Power invests in clean, affordable solar energy* (Mar. 26, 2019), *available at*
https://www.idahopower.com/news/idaho-power-invests-in-clean-affordable-solar-energy
[10] Idaho Public Utilities Commission, Docket No. IPC-E-79-1.4, *Direct Testimony of Matthew T. Larkin* at
[11] (Apr. 4, 2019), *available at*
http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1914/company/20190404LARKIN%20DIRECT.PDF [11] This figure is derived by taking the reported levelized cost of $25.83/MWh, multiplying that rate by 8760 hours per year for 20 years, reducing the value by applying a 15% capacity factor, and dividing by 1000 to convert MW to kW. This formula also works for converting the $36/MWh figure representing the lower bound levelized cost of utility-scale solar in Lazard to the $950/kW figure representing the lower bound capital cost of the same utility-scale solar technology.
[12] *Draft ESRPP* at 7-8; *see also* HDR, Montana Capacity Request for Information (Apr. 13, 2019), provided by NorthWestern via email.
[13] Nevada Public Utilities Commission, Docket No. 18-06, *Volume 11 of 18, Narrative, Supply Side Plan,*
Transmission Plan, Economic Analysis, Distribution Planning, and Financial Plan at 77-79 (Jun. 1, 2018) (describing Copper Mountain Solar 5), *available at*
http://passthrough.fwnotify.net/download/924415/http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESE NT/2018-6/30452.pdf. [14] Arizona Public Service, *2017 Integrated Resource Plan* at 49, 311 & 312 (Apr. 2017), *available at*
https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf.

Inaccurate solar costs have factored into commission decisions in other states not to acknowledge utility resource plans. For example, in its 2017 integrated resource plan ("IRP") Arizona Public Service (APS) modeled solar capital costs of $1,344–1,439/kW — very similar to the figures in the Draft ESRPP — and levelized solar costs of $58/MWh.[14] Joint stakeholder comments questioned APS's levelized cost figure, pointed to "solar PV PPA prices in Nevada, Colorado, and Arizona … in the $29-35/MWh range," and used a value of $35/MWh to determine a proposed alternative portfolio.[14] In the end, the Arizona Corporation Commission declined to acknowledge the IRP, in part on the basis that APS had not shown the plan was "in the best interest of its customers."[15]

In addition to the above concerns about solar cost assumptions, Renewable Northwest questions NorthWestern's choice of including acreage impacts in its assessment of solar.[16] The cost of land leases or purchases associated with solar development is already included in the cost estimates discussed above. If NorthWestern wishes to assess acreage impacts outside the context of resource costs, we recommend that the ESRPP include a similar analysis of acreage impacts associated with gas extraction (such as hydraulic fracturing wastewater ponds) and shipping, including pipeline footprints, and other generation technologies as well.

Response: This issue is discussed in Chapter 11, Response to Public Comments. The cost estimates prepared for NorthWestern by HDR compare favorably to the recent work of the Northwest Power and Conservation Council. Clarifying discussion of the consideration of low cost futures for wind, solar PV, and Li-ion battery technology has been included in Chapter 7. Chapter 13 explains NorthWestern's resource acquisition strategy.

b. Recent Storage Cost Figures Undercut the Draft ESRPP's Assumptions

As with solar, the Draft ESRPP's capital cost estimates for 4-hour battery storage systems of $1,660/kW for lithium-ion battery systems and $1,700/kW for vanadium flow battery systems appear significantly higher than expected based on current indicators of battery storage costs. While the upper bounds for the most recent Lazard's Levelized Cost of Storage Analysis exceed the Draft ESRPP's values, the lower bounds come in considerably lower at $1,140/kW for 4hour lithium-ion battery storage systems and $1,417 for 4-hour vanadium flow systems.[17] Given the rapid declines in battery storage costs in recent years,[18] one would expect the lower

[14] Arizona Corporation Commission, Docket No. E-00000V-15-0094, *Joint Stakeholder Comments on the Integrated Resource Plans of Arizona Public Service Company (APS) & Tucson Electric Power (TEP): Alternative Portfolios* at 15 (Feb. 2, 2018).
[15] Arizona Corporation Commission, Docket No. E-00000V-15-0094, Decision No. 76632 at 3 & 47 (Mar. 29, 2018).
[16] *Draft ESRPP* at 7-7.
[17] *Lazard's Levelized Cost of Storage Analysis—Version 4.0* at 13 (Nov. 2018), *available at* https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.
[18] *Id.* at 3 (describing "significant cost declines" and "continued decreasing cost trends").

bound presented in Lazard to be more appropriate for forward-looking modeling of battery storage costs.

Response: See response above. This issue is discussed in Chapter 11 of the plan.

c. The Draft ESRPP Does Not Adequately Account For Renewables Plus Storage

Although the Draft ESRPP notes that "any future RFP … could include" resources including "[s]olar generation combined with storage" and "[w]ind generation combined with storage"[19] among other options, the document does not consider renewable energy plus storage combinations as discrete resource options even though such combined resources are increasingly proving to be the least-cost, least-risk options in competitive procurement processes. Other utilities such as PacifiCorp are including in their resource-planning efforts combinations such as solar-plus-storage as discrete resource options, and indeed PacifiCorp is modeling solar-plus-storage as a standalone option with costs as low as $1,464/kW.[20]

Actual utility solicitations, however, are yielding even lower costs for renewables-plus-storage. In May 2017, for example, Arizona's Tucson Electric Power announced a PPA priced "significantly less than $0.045/kWh [$45/MWh] over 20 years."[212223] Also in 2017 an All-Source solicitation by Xcel Energy in Colorado drew 87 solar-plus-storage bids at a *median* price of $36.00/MWh — as well as combined wind, solar, and storage at a median of $30.60/MWh.[23] A later refresh of the bids in the solicitation brought consistent results, raising the solar-plus storage median slightly to $38.30/MWh and lowering the combined wind, solar, and storage median to $30.41/MWh.[24] In approving Xcel's procurement of solar-plus-storage as part of its IRP, the Colorado Public Utilities Commission observed:

---

[19] *Draft ESRPP* at 11-3 to 11-4.

[20] PacifiCorp, *2019 Supply Side Table* at 3 (Nov. 1, 2018), *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf.

[21] Peter Maloney, Utility Dive, *How Can Tucson Electric get solar + storage for 4.5¢/kWh?* (May 30,

[22]), *available at* https://www.utilitydive.com/news/how-can-tucson-electric-get-solar-storage-for45kwh/443715/. [23] Colorado Public Utilities Commission, Docket No. 16A-0396E, *2017 All Source Solicitation 30-Day Report* at 9 (Dec. 28, 2017), *available at* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=878518&p_s ession_id=. [24] Colorado Public Utilities Commission, Docket No. 16A-0396E, *2017 All Source Solicitation 30-Day Report Update*, Attachment A (Mar. 1, 2018), *available at* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=881732&p_s ession_id=. [25] Colorado Public Utilities Commission, Docket No. 16A-0396E, Decision No. C18-0761 at 32 (Sept. 10,

[23]), *available at* https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=892346&p_s ession_id=.

> We concur with Public Service that the CEP [Colorado Energy Plan] Portfolio will enable the Company to take "a large step into the utilization of battery storage." We also agree with WRA [Western Resource Advocates] that the competitive pricing of battery storage in response to the competitive solicitation was one of the most surprising and welcome results. The proposed acquisitions will offer a learning opportunity to examine how solar paired with storage can enhance system reliability and flexibility.[25]

And one of the projects included in the 2018 NVEnergy procurement referenced above is a 25year, 101 MW solar PPA paired with a 25 MW x 4 hour battery storage system coming in at $26.50/MWh for energy, as well as a $7,755/MW-month capacity payment for a ten-year term.[24]

Each of the above procurements reflects the value of the federal Investment Tax Credit ("ITC") at a full 30%, prior to initiation of the ITC sunset.[25] But, as is discussed above, solar and solarplus-storage costs are rapidly falling regardless of subsidies,[26] and there may be projects capable both of harnessing the 30% ITC (or first step-down of 26%) and bidding into any procurement process initiated as a result of this ESRPP.

We recommend that NorthWestern fully account for the low costs and full suite of benefits of renewables-plus-storage that are increasingly resulting in these combined resources winning competitive solicitations.

Response: NorthWestern did not consider renewable/battery combinations in its plan. NorthWestern already has a large portfolio of renewable resources which allows for the synergies of batteries to be developed without adding additional renewables.

As discussed in Chapter 11 and elsewhere in the Plan, the purpose of the plan is not to select a resource or a preferred portfolio of resources. NorthWestern will rely upon the competitive solicitation process discussed in Chapter 13. We anticipate that renewables/storage combinations will be bid into a competitive solicitation and that the process will provide more granular information.

2. The Draft ESRPP Appears To Underestimate the Risks Associated with Gas Generation

[24] Nevada Public Utilities Commission, *supra* n.13 at 73-75.

[25] *See, e.g.,* Colorado Public Utilities Commission, *supra* n.24 at 20.

[26] Recall that the Lazard figures quoted above are for *unsubsidized* solar and storage.

It is unclear precisely how and to what extent the Draft ESRPP addresses the risks associated with new gas generation, and in particular gas price volatility, but what indicators there are in the document suggest that the risks are underestimated. For example, the Draft ESRPP assigns a value of $0.00 to the "Avoided Risk (e.g., reduced price volatility)" associated with net metered systems.[27] References to price volatility in the Draft are generally limited to projections of NorthWestern's potential reliance on the market.[28] And the Draft ESRPP reports comparable risks associated with higher renewable-energy portfolios relative to the base case (which meets identified resource needs with new thermal generation), resulting in higher risk-adjusted costs for those portfolios relative to base.[29] As will be discussed in more detail below, we would expect to see significantly higher risks associated with gas as compared to renewables.

At a high level, not only are renewables (which have a fuel cost of zero) and battery storage assets (which can draw charge when market prices are low and discharge when market prices are high) less risky than thermal resources (which have variable fuel costs and are susceptible to price spikes), but also energy-system actors and regulators are increasingly acknowledging that building new gas resources now is a bad bet due in part to risks and uncertainties related to the economics of gas.

At a high level, a recent report by the Sightline Institute observes that the fracking boom driving today's baseline gas prices appears financially unsustainable.[30] And even at today's pace of gas production, gas generation is subject to price spikes partly as a function of weather-induced demand. For example, the Northwest Energy Coalition issued a report on the "Double Squeeze" that resulted in record gas and, as a result, electricity prices across the northwest in February 2019.[31] The aggregate impacts of that price spike are as-yet uncalculated, but the spike does highlight real concerns; just last week, for example, PacifiCorp released IRP materials acknowledging that "[r]ecent events have highlighted natural gas pipeline delivery risk" and pointing to a significant role for battery storage as a potential source of future flexible capacity to meet reliability needs.[34]

---

[27] *Draft ESRPP* at 4-24, Table 4-9; see also Navigant, *Net Energy Metering (NEM) Benefit-Cost Analysis* at 13 (Mar. 29, 2018), provided by NorthWestern via email.
[28] *See*, *e.g.*, *Draft ESRPP* at 10-5.
[29] *See*, *e.g.*, *id.* at 10-16 ("The Wind portfolio does have a lower carbon intensity … but the risk-adjusted NPV is $176 million more than Base"); *id.* at 10-17 ("The Solar PV portfolio has a lower carbon intensity … but the risk-adjusted NPV is $197 million more").
[30] Sightline Institute, *Energy Market Update: More Red Flags on Fracking* (Mar. 2019), https://sightlinewpengine.netdna-ssl.com/wp-content/uploads/2019/03/Q4-2018_More-Red-Flags-on-Fracking_March2019.pdf (outlining "Wall Street's growing reluctance to finance fracking" and "[f]rackers' persistent inability to produce positive cash flows" and describing "the fracking sector as a speculative enterprise with weak and uncertain fundamentals").
[31] Fred Heutte, Northwest Energy Coalition, *Double Squeeze: How the Arctic Express and natural gas constraints are turning the West Coast gas and power markets upside down* (Mar. 6, 2019), *available at* https://nwenergy.org/wp-content/uploads/2019/03/double-squeeze-final.pdf.

Two more events occurred last week highlighting the shift away from gas generation as a preferred source of flexible capacity: first, Southern California Edison applied for approval of a plan to procure 195 MW of battery storage for flexible capacity following an RFP that also featured gas generation bids[35]; and second, the Indiana Utility Regulatory Commission denied a utility's application for approval of a proposed gas plant on the basis that the application "does not present an outcome which reasonably minimizes the potential risk that customers could sometime in the future be saddled with an uneconomic investment or serve to foster utility and customer flexibility in an environment of rapid technological innovation."[36]

The Indiana Utility Regulatory Commission is not alone; the Arizona Corporation Commission's decision not to acknowledge the IRPs of Arizona Public Service (referenced above) and Tucson Electric Power was also based in significant part on those utilities' plans to procure new gas generation.[37] Indeed, in addition to declining to acknowledge the utilities' IRPs, the Commission "ordered that a Load Serving Entity may not procure by purchase, acquisition, or construction a generating facility of natural gas energy of 150 MW of capacity or more" except under stringent circumstances including comparative analysis of gas generation with storage and submission of a procurement plan for later Commission approval.[38]

Additional evidence demonstrates that concerns about gas risks are well-founded. ISO-New England recently published an interesting estimate of the aggregate electricity-price impacts of weather-influenced gas price spikes over two weeks spanning December 2017 and January 2018.[39] Specifically, ISO-NE's analysis presents the expected avoided generation costs if unbuilt offshore wind had been available to displace gas generation during the period of the gas

34 PacifiCorp, *2019 Integrated Resource Plan (IRP) Public Input Meeting* at 39, 40-43 (Apr. 25, 2019), *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_April_25_2019_PIM.pdf.

35 California Public Utilities Commission, Docket No. 19-04-XXX, *Testimony of Southern California Edison Company (U 338-E) in Support of Its Application for Approval of the Results of Its 2018 Local Capacity Requirements Request for Proposals (LCR RFP)* (Apr. 22, 2019), *available at* http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/11D80C3CF6F46FEF882583E5000118BE/%24FILE/ A1904XXX-PUBLIC%20SCE%20Testimony%20in%20Support%20of%20Appl%20for%20App%20of%20Results%20 of%202018%20LCR%20RFP%20SCE-01.pdf.

36 Indiana Utility Regulatory Commission, Cause No. 45052, *Order of the Commission* (Apr. 24, 2019), *available at* https://www.in.gov/iurc/files/45052_ord_20190424102046480.pdf.

37 Arizona Corporation Commission, *supra* n. 16, at 48-53.

38 *Id.* at 51-52.

39 ISO New England, *High-Level Assessment of Potential Impacts of Offshore Wind Additions to the New England Power System During the 2017-2018 Cold Spell* (Dec. 17, 2018), *available at* https://www.isone.com/static-assets/documents/2018/12/2018_isone_offshore_wind_assessment_mass_cec_production_estimates_12_17_2018_public.pdf.

price spike.[32] The range of potential avoided costs from relying on wind to displace gas across the ISO-NE footprint for just those two weeks topped out at $85 million.[41] Against this backdrop of recent gas price volatility, NorthWestern's annualized risk premium of $112 million for its gasoriented base case appears significantly lower than one would expect.

The Draft ESRPP paraphrases the PSC in acknowledging that "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."[33] Renewable Northwest appreciates this observation. New gas resources are both risky and long-lived, and to the extent NorthWestern contemplates investing in these resources, it should likewise commit to bearing the full suite of risks associated with gas price volatility rather than maintaining the possibility of passing the costs of future price spikes on to its customers.

Response: This issue is addressed in Chapter 11.

3. The Draft ESRPP's Portfolio Modeling Results Are Out of Step with Other Utilities and Utility Regulators

Observations above regarding low renewable energy and storage costs and high gas risks are not unique to Renewable Northwest or to the advocacy community; rather, utilities around the country are making the same observations and using them to drive planning efforts, resulting in resource portfolios that look very different from the Draft ESRPP's portfolio modeling results.

For example, Consumers Energy in Michigan has proposed meeting its "capacity needs which occur during the period of time covered by this IRP with demand-side management resources, solar generation, and battery technology" rather than new gas generation, identifying the plan as an "opportunity to shift from large, baseload generating plants to modular resources that are better able to reliably balance capacity needs with supply."[43] Xcel Energy followed by announcing a zero-carbon electricity goal in December 2018,[34] Idaho Power joined them in March 2019,[45] and Avista followed in April 2019.[35] These utility announcements are being reinforced by procurement decisions. As mentioned above, for example, Southern California

---

[32] *Id.* [41] *Id.* at 3, Table 2.

[33] *Draft ESRPP* at 2-6. [43] Michigan Public Service Commission, Case No. U-20165, *Direct Testimony of Richard T. Blumenstock on Behalf of Consumers Energy Company* at 4 (Jun. 2018), *available at* https://mipsc.force.com/sfc/servlet.shepherd/version/download/068t000000231usAAA.

[34] Press release, *Xcel Energy aims for zero-carbon electricity by 2050* (Dec. 4, 2018), *available at* https://www.xcelenergy.com/company/media_room/news_releases/xcel_energy_aims_for_zerocarbon_electricity_by_2050. [45] Press release, *Idaho Power sets goal for 100-percent clean energy by 2045* (Mar. 26, 2019), *available at* https://www.idahopower.com/news/idaho-power-sets-goal-for-100-percent-clean-energy-by-2045/.

[35] Press release, *Avista builds on commitment to renewable energy with goal of 100 percent clean electricity by 2045* (Apr. 18, 2019), *available at* http://investor.avistacorp.com/news-releases/newsrelease-details/avista-builds-commitment-renewable-energy-goal-100-percent-clean.

Edison identified solar-plus-storage as the best resource to meet its need for flexible capacity following a recent competitive solicitation that also included gas bids.[36]

Utility regulators are drawing the same conclusions and pushing utilities away from investment in new gas resources. Recall that the Arizona Corporation Commission declined to acknowledge IRPs filed by Tucson Electric Power and Arizona Public Service due in part to overreliance on gas,[37] and that the Indiana Utility Regulatory Commission denied an application for approval of a gas plant procurement due to the risky nature of the investment.[38]

Notably, now-outdated versions of Idaho Power's and Arizona Public Services' resource plans were both included in the Ascend Analytics "WECC Market Outlook and Modeling" provided by NorthWestern as one of the technical documents forming the basis for the Draft ESRPP. The Ascend document noted that Idaho Power "is proposing to add peaking capacity in the form of reciprocating engines as well as generic generation in combined cycle combustion turbines."[39] And it added that "APS plans to install over 4GW of gas generation."[40] As is explained above, we now know that it is unlikely that either utility will be adding new gas generation in the foreseeable future.

While each utility may have unique concerns or circumstances that result in different decisions as to how a resource plans are implemented, there is a remarkable consensus developing in the field of utility resource planning and regulation: renewables and storage are the most cost effective and promising technology to meet most utility resource needs, while gas generation is a risk that is not worth taking. It appears likely that the Draft ESRPP's contrary conclusions are at least partly a result of the Draft's outdated renewable-energy and storage cost assumptions and its underestimate of gas risks as described above.

Response: These issues are addressed in Chapter 11.

4. Additional Detail Would Assist Stakeholders in Providing Useful Comments on the Draft ESRPP's Portfolio Modeling

[36] California Public Utilities Commission, *supra* n.35.
[37] Arizona Corporation Commission, *supra* n.16.
[38] Indiana Utility Regulatory Commission, *supra* n.36.
[39] Ascend Analytics, *WECC Market Outlook and Modeling* at 21.
[40] *Id.* at 25.

Renewable Northwest appreciates NorthWestern's responsiveness to our request for additional information to inform these comments; we submitted a request on April 11, 2019, and NorthWestern provided materials on April 16, 2019 and April 18, 2019.

Even with this additional information, however, there is insufficient material available to develop comments in the same level of detail that we provide to other utilities in the region when engaging with their resource plans. We understand from NorthWestern that some technical materials were still in development at the time the Draft ESRPP was released to the public, and we hope that the full suite of materials, data, and assumptions underlying NorthWestern's portfolio analysis will be made available to stakeholders at the time the ESRPP is formally filed with the Commission.

Response: Thank for you the feedback. The ETAC is discussed in detail in Chapter 11.

III. CONCLUSION

Renewable Northwest appreciates this opportunity for informal comment on NorthWestern's Draft ESRPP. We hope NorthWestern will consider the information and concerns identified above and take them into account in preparing their formal ESRPP, and we look forward to working with NorthWestern and other stakeholders to identify optimal solutions for meeting the needs of NorthWestern's customers at the least long-term cost throughout the following regulatory process.

Sincerely,

Max Greene
Staff Counsel & Analyst
Renewable Northwest
max@renewablenw.org

Jeff Fox
Montana Policy Manager
Renewable Northwest
jeff@renewablenw.org

of 10

May 5, 2019

Sierra Club Comments on Northwestern Energy's 2019 Electricity Supply Resource Procurement Plan

Sierra Club appreciates the opportunity to provide comments on Northwestern Energy's ("NWE") Draft 2019 Electricity Supply Resource Procurement Plan ("2019 Draft Procurement Plan"). We have several concerns with NWE's plan to acquire 725 MW of capacity resources by adding up to 200 MW a year from 2022 to 2025.

1. NWE's 2019 Draft Procurement Plan does not adequately address the issue of potential regional overinvestment

In its December 20, 2017 Order, the MPSC pointed out that "other utilities' integrated resource plans ("IRPs") also anticipate capacity acquisitions," and "[i]f each of the utilities in the region were to acquire all the capacity resources identified in its IRP, the region would risk over-investing in capacity resources, which would result in economic inefficiency and unnecessary rate increases for customers."[1] Northwestern's 2019 Draft Procurement Plan fails to address this concern.

Response: This issue is addressed in Chapter 11, Response to Public Comments.

Northwestern references the Pacific Northwest Power Supply Adequacy Assessment for 2023,[2] which concludes that the additional capacity needed in the entire region is estimated to be approximately 300 MW in 2021 and an additional need for 300 to 400 MW in 2022.[3] The study's conclusion begs the question of why Northwestern would need to acquire almost the same amount of capacity as the entire regional deficit. The Draft Procurement Plan does not answer the key questions of what other utilities in the region are planning, and why

[1] MPSC Supplemental Comments in Response to Northwestern Energy's 2015 Electricity Supply Procurement Plant, Dkt. No. N2015.11.91, para. 10 (Dec. 20, 2017), available at http://psc2.mt.gov/Docs/ElectronicDocuments/pdfFiles/N20151191SuppComments.pdf

[2] NWE Draft 2019 Procurement Plan at 2-10, citing Pacific Northwest Power Supply Adequacy Assessment for 2023, NWPCC, June, 14, 2018 (NWE 2019 Plan), available at

[3] NWE 2019 Plan at 2-10 (emphasis added).

Northwestern must act immediately to acquire new resources instead of continuing to rely on the market.

Response: This issue is addressed in Chapter 11.

Northwestern contends that its plan to join the Western Energy Imbalance Market ("EIM") in 2021 impacts its need to acquire capacity.[4] But joining the EIM does not mean that NWE must own or operate its own resources.

As an initial matter, the 2019 Draft Procurement Plan description of how the EIM requires NWE to demonstrate on an hourly basis that it has the resources and ramping capacity to meet its own needs[5] is incomplete. The EIM is fundamentally a balancing market, and its purpose is to efficiently allocate operational generation on a real-time basis. Participation in the EIM does, in fact, require that participants demonstrate that they have sufficient resources to meet their obligations under their own submitted base schedules. It does not, however, require that NWE opt in its entire load or all of its generation resources. The market is entirely voluntary - balancing authorities and participants submit base schedules and then nominate specific resources to meet those base schedules. Not all of a utility's needs must be met through the EIM. The EIM's sufficiency rules simply ensure that no party intends on leaning on EIM imports as a mechanism of meeting reliability.

NWE's current market participation is fundamentally no different than requirements under the EIM. NWE's market purchases are targeted to meet peak requirements and thus are likely firm, scheduled purchases. In EIM participation, those firm purchases can either be nominated into the EIM (presuming NWE has such discretion in its purchase contract) or can be deducted from NWE's base schedule. EIM's balancing test does not, unto itself, support the need for acquisition. Such an outcome would be absurd and antithetical to the purpose of a regional market, which is to allow cost-effective resources (of which there are many) to trade with a lower hurdle rate.

In addition, the creation of a full Western Regional Transmission Operator (RTO) would further obviate, or at least blur, the need for additional owned resources at NWE. A larger market footprint, operating not only on a real-time basis but also in the commitment of units, would help ensure that resource adequacy needs are met across the region, rather than just within the service territory of a single market participant. Depending on the form of such a market construct, NWE might either be required to demonstrate its own resource adequacy (for which it could likely also rely on firm market options) or participate in a wider reserve sharing mechanism.

Response: This issue is addressed in Chapter 11.

---

[4] NWE 2019 Plan at 1-2

[5] NWE 2019 Plan at 5-12.

2. The Modeling Constraints And Assumptions Are Stacked Against Renewables

NWE claims that its Request for Proposals ("RFP") will be open to all sources, and thermal generation is not the presumptive winner, however, the input assumptions would appear to make it nearly impossible for the model to select anything other than thermal generation. NWE's model generally selects thermal generation, and "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….[and] the risk-adjusted NPV of the No Carbon Additions is $523 million more than that of the Base portfolio."[6] It is clear from the results that NWE is seeking to minimize the likelihood of accepting clean energy bidders.

Most problematically, NWE included a series of unsupported constraints on the model that create impossible criteria in which to build reasonable portfolios of storage and renewable energy options. Individually, these criteria are problematic, but in concert they are wholesale modeling blocks to building clean energy, and must be rectified.

Response: This issue is addressed in Chapter 11.

NWE appears to provide little or no load carrying capacity to wind or solar. A key criterion for modeling the integration of renewable energy into the grid is the examination of the capabilities and performance of renewable energy options. NWE fails to adequately address the peak availability of wind or solar resources, only stating that during a historic period in 2017 NWE's existing "wind contributed very little of its maximum generation capability."[7] The report provides no quantitative estimation of the capacity contribution of solar, simply stating that "solar PV does not contribute to the capacity required during Northwestern's winter peak load hours."[8] This lack of quantification, or even formal demonstration, is problematic. In shortcutting around an assessment of effective load carrying capability ("ELCC"), or the potential that solar, wind, and pumped storage could act in concert, NWE effectively excluded renewable energy from the analysis process. The results of this are apparent in the resource selection process where NWE tests the impact of individual renewables on its peak requirements (Table 10-3). In every scenario, NWE's model requires approximately the same number of megawatts of fossil (or in one case, fossil and storage), providing no value to the wind or solar. To rectify this assumption, NWE must (a) provide a quantitative demonstrate of wind and solar ELCC, (b) look at scenarios with overnight storage from pumped hydro in concert with solar, and/or (c) allow for bids comprised of multiple technologies that collectively meet NWE's requirements.

Response: This issue is addressed in Chapter 11.

---

[6] NWE 2019 Plan at 10-19--20.
[7] NWE 2019 Plan at 1-5.
[8] NWE 2019 Plan at 10-17.

NWE restricts resource additions to 200 MW per year over a four year period.[9] NWE assesses a current gap of 645 MW, and a future need of "about 725 MW by 2025."[10] To fulfill that need, NWE allows the model to select resources, but up to only "about" 200 MW per year,[11] and over the narrow window from 2022 to 2025.[12] To fulfill the stated obligation to fill a 725 MW obligation over a four-year window, the model **must** select around 200 MW per year of firm capacity. However, because of the limitation on total annual build, the model **cannot** select more than 200 MW per year. As such, the model is restricted to build firm capacity resources only, and cannot search for economic clean energy portfolios. A clean energy portfolio can be comprised of a combination of renewable energy, storage, and even demand-side management programs. However, because variable renewable energy typically does not match peak requirements, a clean energy portfolio - even a cost effective clean energy portfolio - will require a greater total nameplate capacity than a stated need. By restricting the resource additions to 200 MW per year over a four year period, the model is unable to select a reasonable portfolio of economic clean energy options.

Response: This issue is addressed in Chapter 11.

NWE restricts market sales to 10% over annual customer load. [13] In most circumstances, a utility should seek to minimize excess market sales during the procurement process for new energy - cost effective resources may lead to a temptation to become a large net exporter. However, renewable energy options may require a substantial amount of market trading, particularly to realize the benefits of geographically distributed renewables across states or regions. A restriction on market sales reduces the opportunity to sell excess renewable energy during hours it is not needed to meet requirements or charge storage, and restricts the total build of renewable energy that could contribute to cost effective renewable/storage combinations.

Response: The 10% assumption is necessary to prevent overbuilding of resources based upon market sales; NorthWestern is not a market speculator. As explained in Chapter 13, renewable/storage combinations will be able to bid into competitive solicitations.

NWE's restriction on near-term builds forgoes opportunities to tap federal tax credits. NWE states that it assumes that no new resources could come online prior to 2022 due

[9] NWE 2019 Plan at 10-3.
[10] NWE 2019 Plan at 1-3.
[11] NWE 2019 Plan at 10-3. "Resource additions were limited to about 200 MW per year."
[12] NEW 2019 Plan at 10-3. "Resources are not placed in service prior to 2022." and must reach a 16% reserve margin by 2025.
[13] NWE 2019 Plan at 10-3. "Market sales were constrained to no more than 10% over annual customer load."

to the competitive solicitation process.[14] While holding to a competitive bid process is reasonable and correct, the restriction on nearer term builds would appear to preclude renewable projects from taking advantage of the Solar Investment Tax Credit (ITC) or Production Tax Credit (PTC) benefits.

Response: The model was predicated on filling a capacity shortfall that presently exists by pursuing a competitive solicitation that would be in-service by 2022. This is not the same as a restriction on near term builds.

NWE's assumed costs for unsubsidized renewable energy projects are high, and increase unreasonably. NWE provides an assessment of new resource costs for Montana as of December 2018.[15] The assumed unsubsidized costs of renewable energy are at the high end, or higher, than Lazard's range of estimated capital costs from November 2018. The Lazard study shows wind at $1,150-$1,550/kW;[16] in contrast, NWE assumes $1,410/kW - and increasing in the base scenario. Similarly, for solar costs, Lazard shows solar at $950-$1,250/kW; in contrast, NWE assumes $1,330/kW - both above the high end cost and increasing.

Response: This issue is addressed in Chapter 11.

NWE does provide an alternative downward sloping trajectory for the cost of wind, solar and battery,[17] but it doesn't actually use these trajectories, rendering them a red herring. The only reference made to downward sloping cost trajectories for renewables is where NWE states that the model did not select renewables or storage "even when low-cost futures for wind, solar PV, and Li-ion were included for selection in the ARS model." This finding aside, due to the other constraints preventing the section of renewable energy (see above), NWE fails to provide an estimated cost for the No Carbon Additions scenario under declining renewable price curves.

The cost of the No Carbon Additions scenario would likely be substantially lower if it included NWE's assessment of falling renewable prices, consistent with recent and expected trends.[17] From a rough-scale visual review using the chart provided by NWE in Figure 7-2, it appears that "low cost" renewable and storage prices are about 30% lower in 2023 than in the

14 NWE 2019 Plan at 10-3.

15 NWE 2019 Plan at 7-22, 7-23.

16 Lazard Cost of Energy v12.0 . November 2018. "Key Assumptions" https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

17 NWE 2019 Plan at 7-24, Figure 7-2.

17 Forbes. December 3, 2018. Plunging Prices Mean Building New Renewable Energy Is Cheaper Than Running Existing Coal. https://www.forbes.com/sites/energyinnovation/2018/12/03/plunging-prices-mean-building-new-renewable-energy-is-cheaper-than-running-existing-coal/#2770a10631f3

base scenario. By 2034, where wind apparently becomes a larger fraction of the No-Carbon Additions scenario,[18] wind in the "low cost" price trajectory is apparently 60% less expensive than the base increasing prices assumed by NWE. It is reasonable therefore to assume that the cost of all new capital projects in the No Carbon Additions are at least 30% below modeled prices shown Figure 10-3 on a present value basis, and likely much lower. If we adjust downwards the value of "New Revenue Requirement" for the No Carbon Additions scenario by 30%, we reduce the cost of the scenario by $694 million, or down to a total of $5,546 million NPV. The No Carbon Additions scenario is, under these circumstances, the least cost plan by a margin of $171 million. In other words, assuming that renewable energy prices continue to fall in line with NWE's projections and as projected by most utility analysts, **the case in which future needs are met through renewable energy and storage is the least cost option.**

Response: This issue is addressed in Chapter 11.

NWE's carbon price assumptions and implementation appear unreasonable. NWE cites an MPSC rejection of a carbon adder in avoided cost calculations as the basis for the decision that it "is not including a carbon cost in the base case for the 2019 Plan," and instead only considering carbon as a sensitivity.[19] It is unreasonable not to consider carbon pricing in the base scenario of long-term resource acquisition planning. While the current administration may not favor restrictions on emissions, public sentiment and the EPA endangerment finding make it highly likely that there will be an implicit or explicit price on carbon within the next federal administration.

The carbon prices that NWE selects as part of the sensitivity are by no means a reasonable baseline or "high" set of scenarios either. The baseline does not assess a carbon price until 2028, or nine years from now, implying a delay in implementation for another two administrations. That carbon price, at $4.5/ton (2016$)[20] is barely enough to register in resource planning or dispatch, and cannot reasonably imply a federal or regional mechanism to reduce carbon emissions. A price that represents pain without gain is not a reasonable assumption. Overall, the fact that this low and delayed carbon price represents a "middle" sensitivity discounts any risk associated with carbon emissions. The "high" carbon price in 2025 starts at a level that may impact decisions and dispatch, but represents an operational-level of carbon price (i.e. a political compromise). A risk assessment carbon price would use a social cost of carbon - closer to $40/ton in 2025 - to assess the impact incurred through an administration, rulemaking, or popular sentiment towards pricing carbon at its externality cost.

[18] NWE 2019 Plan at 10-23, 10-24. "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." See also Figure 10-6.
[19] NWE 2019 Plan at 9-12.
[20] NWE 2019 Plan at 9-14, Table 9-1.

For comparison, neighboring utility Rocky Mountain Power (PacifiCorp) is using a reference case carbon price of ~$11/ton CO2 in 2025, and a high cost carbon price of $20/ton CO2 in 2025.[21]

Response: This issue is addressed in Chapters 7 and 11.

Finally, Figure 10-3 implies that carbon prices are assessed as part of the overall cost of each portfolio. Therefore, while the "base" and "carbon cost" scenarios have almost identical scenario construction (trading off some small RICE engines for medium RICE engines),[22] the "carbon cost" scenario is $166 million more expensive.[23] Similarly, the "high carbon cost" scenario is almost exactly identical to the "base" scenario, and yet is priced $317 million more than the "base" case. The only way in which these scenarios deviate by that degree is in the actual cost of carbon assigned in the model. A comparison of total scenario costs with and without a carbon adder is appropriate for the comparison of portfolio costs.

Response: This issue is addressed in Chapters 7 and 11.

3. Northwestern did not provide stakeholders with critical information needed to evaluate its modeling.

While Sierra Club is pleased that the Commission and its experts have some access to the Powersimm modeling, and Northwestern has held additional meetings, stakeholders remain largely uninformed about the model. As MPSC recognized in its Order on NWE's 2017 Plan, "a model that is systematically unavailable to anyone other than NorthWestern creates an information asymmetry that undercuts the legitimacy of NorthWestern's resource-planning exercise."[24] The inputs and assumptions into the model are extremely important because the RFP bids will be evaluated through the model. We urge Northwestern to make the full Appendix II available for the public to review and comment when the final procurement plan is filed with the Commission.

---

[21] PacifiCorp IRP Public Input Meeting. October 9, 2018. Page 15.
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_I
RP/PacifiCorp_2019_IRP_October_9_2018_Public_Input_Meeting.pdf

[22] NWE 2019 Plan at 10-19, Table 10-4

[23] NWE 2019 Plan at 10-21, Table 10-3

[24] MPSC Comments in Response to Northwestern Energy's 2015 Electricity Supply Procurement Plant, Dkt. No. N2015.11.91, para. 17 (Feb. 2, 2017), available at
http://psc2.mt.gov/Docs/ElectronicDocuments/pdfFiles/N20151191Comments.pdf

Response: This issue is addressed in Chapter 11. Volume 2 will be included when the 2019 Plan is filed with the Montana Public Service Commission.

Thank you for your consideration of the issues we have identified, and we hope NWE can address them in the final procurement plan. Please do not hesitate to contact us with any questions.

Respectfully submitted,

Andrea Issod
Senior Attorney
Sierra Club Environmental Law Program
2101 Webster St., Suite 1300
Oakland, CA 94612 (415)
977-5544
andrea.issod@sierraclub.org

Jeremy Fisher
Senior Strategy and Technical Advisor
Sierra Club Environmental Law Program
2101 Webster St., Suite 1300
Oakland, CA 94612 (415)
977-5536
jeremy.fisher@sierraclub.org

DRAFT

Comments on NorthWestern Energy's Draft 2019 Electricity Supply Resource Procurement Plan

Prepared for Montana Public Service Commission

May 5, 2019

AUTHORS

Bob Fagan
Nina Peluso
Rachel Wilson

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

1. INTRODUCTION

NorthWestern Energy ("NorthWestern," "NWE," or "the Company") issued its *Draft 2019 Electricity Supply Resource Procurement Plan* ("Draft Plan") on March 5, 2019. In that Draft Plan, NorthWestern describes its current capacity deficit of 645 megawatts (MW), which is expected to increase to 725 MW by 2025 without new peaking capacity. NorthWestern currently meets peak demand needs through market purchases but its Draft Plan proposes to add up to 200 MW per year of flexible capacity from 2022 to 2025 in order to close its capacity gap. Flexibility capacity is defined by the Company as a resource that can be dispatched on-demand to ramp up or shut down relatively quickly. NorthWestern's least-cost resource portfolio that results from its PowerSimm capacity expansion modeling consists exclusively of new flexibility capacity in the form of gas-fired Reciprocating Internal Combustion Engines (RICE). The modeling results do not represent a commitment to RICE generation, however. The Company intends to procure any new resources through the RFP process, soliciting competitive proposals from a variety of resources. NorthWestern has stated that the resources procured through these competitive solicitations may or may not be those identified in the modeling conducted for the Draft Plan.

NorthWestern's 2015 Electricity Supply Resource Procurement Plan ("2015 Plan") was submitted in March 2016 and, for the first time, included a capacity-based long-term planning approach to address the imbalance between projected peak loads and the Company's owned and contracted physical resources. The Company proposed a strategy to achieve minimal resource adequacy over a ten-year period, acquiring flexible generating capacity according to the results of an analysis of portfolio costs and risks using the PowerSimm planning model developed by Ascend Analytics. In February 2017, the Montana Public Service Commission ("PSC" or "Commission") issued comments finding the 2015 Plan to be deficient in the following areas: 1) the relationship between regional resource adequacy and NorthWestern's system adequacy; 2) the precision with which NWE defined the need for various types of capacity; 3) the scope of resources and areas of uncertainty evaluated in the portfolio cost modeling process; and 4) the quality of the stakeholder process leading up to the issuance of the 2015 Plan. In supplemental comments issued by the PSC in December 2017, the Commission emphasized the relationship between the regional electric system and NorthWestern's capacity needs, the importance of testing the market for available resources, and requested a limited forecast horizon of 15 years. The PSC also delayed the filing of NorthWestern's next resource plan, directing the Company to file that plan in December 2018.

Synapse Energy Economics, Inc. was hired as a consultant to the Montana PSC to evaluate NWE's efforts in its current Draft Plan to remedy the Commission's concerns with the 2015 Plan. This included participation in NorthWestern's stakeholder process and review of the PowerSimm model that the Company uses for portfolio modeling. These comments address our findings as to the adequacy of the Draft Plan, both with respect to remedying specific areas of concern identified by the PSC and additional concerns that we describe in subsequent sections of this report.

2. Draft 2019 Electricity Supply Resource Procurement Plan

2.1. Resource adequacy

In its comments on the 2015 Plan, the MT PSC made several critiques and suggestions related to resource adequacy. The Commission stated that the 2015 Plan should have, but did not, determine resource adequacy needs by evaluating NWE load requirements in relation to regional peak demand and regional capacity, and suggested that NWE should consider whether it should assume responsibility for a certain portion of regional capacity need. The Commission also stated that the resource adequacy standards used were not sufficiently justified with supporting analysis, and that detailed consideration should be given to anticipated requirements for participating in an organized market if such requirements are alleged to drive capacity needs.

Response: NorthWestern has done considerable work to evaluate its peak load requirements relative to the regional needs (see Chapter 2). In addition, NorthWestern, along with several other northwest utilities, engaged Energy and Environmental Economics ("E3") to study the issue of resource adequacy in the northwest. E3 presented the results of that study to the MPSC at an informational meeting on April 2, 2019. The full study is included in Volume 2. A key finding of the E3 study is that the northwest needs capacity additions in the near-term to accommodate load growth and the planned retirement of coal plants in the region. Additionally, E3 found because the region lacks a formal mechanism for tracking physical capacity, short-term market purchases or "front office" transactions create a risk of double-counting available capacity.

Regarding the question of whether NorthWestern should assume responsibility for a certain portion of regional capacity need , the answer is clear. In all markets (and regions without markets that have a formal resource adequacy requirement), load-serving entities are responsible to carry enough capacity to meet their own peak need plus a reserve margin. The specifics of a resource adequacy program - for example, whether the reserve margin is calculated based on a coincident peak or a non-coincident peak, the amount of capacity that can be procured in the short-term vs. long-term, etc – can vary. However, these differences are small when compared to the magnitude of NorthWestern's current capacity shortage. In other words, NorthWestern doesn't need to know the specifics of a future resource adequacy program in the northwest in order to begin addressing our shortage today. The specific trajectory of NorthWestern's capacity addition plans can be adjusted in future planning cycles as more detail becomes available.

In the 2019 Draft Plan, NorthWestern notes that the regional shortfall in capacity expected in 2021-2022 is on the order of 300-400 MW (page 2-10). Southwest supply availability, and hydro levels, could eliminate or increase this estimated need. NWE also notes that different entities in the region have different capacity positions – e.g., Avista (notably, now an expected Energy Imbalance Market (EIM) participant in 2022) is long on capacity (page 2-13) while NorthWestern is short. These facts support the general notion that bilateral procurements of capacity should be an economically efficient way to ensure there is not an overbuilding of requirement in the Pacific Northwest, especially for a region about to become better integrated, economically, through the EIM – which also allows for more efficient "sharing" of any needed "flexible" capacity. The impending entry of more Pacific Northwest entities into the CAISO EIM, and enhancements to that EIM (towards an RTO-like construct in 2025), make it even more certain that a significant part of the economically optimum outcome for ratepayers in the region is to "share" (i.e., buy and sell) capacity resources and not overbuild.

Response:

- NorthWestern expects that bilateral transactions will continue to be a part of its supply portfolio into the foreseeable future. However, a distinction must be made between long-term bilateral transactions and shot-term bilateral transactions. Long-term bilateral capacity transactions have a potential place in the resource planning process, and as we have stated, NorthWestern expects to solicit bids from potential sellers of existing capacity and capacity that is in development in the RFP process. Short-term transactions, on the other hand cannot be relied upon from a planning perspective unless a regional resource adequacy program, either through an organized market or other entity, is in place. Such a resource adequacy program would likely include a limit on the amount of capacity that could be procured on a short-term basis. For example, the current resource adequacy program in SPP allows seasonal capacity purchases, only up to 25% of the planning requirement. The remaining 75% must be owned or procured for terms of more than one year. Any limits on the amount of short-term capacity that could be used in a future northwest resource adequacy program would be based on the specifics of this region.
- As described in the draft Plan and in the E3 study, the region is facing a capacity shortage, not an economic problem of overbuilding capacity. This is particularly true of NorthWestern, which has leaned on the capacity owned by others for many years and is far short of controlling the capacity to meet its own requirements.
- It is important to emphasize that EIM is not a capacity market. EIM is an intra-hour energy market. It does not address capacity margins or any other aspect of resource planning. To the contrary, a key feature of that market is that each entity must be self-sufficient and not lean on the EIM. The fact that Avista or any other entity has announced plans to join the EIM is irrelevant from a resource adequacy perspective.
- It is also important to note that the EIM does not allow for sharing of flexible capacity. Each entity must hold sufficient flexible capacity on its own. The EIM facilitates efficient dispatch of that capacity. It is true that the overall need for flexible capacity is reduced in the EIM footprint compared to what each entity would need on its own due to the diversity of loads and generation across the footprint. However, this does not mean that the capacity to meet this need is shared or traded in the EIM market.

Given that context, NorthWestern's statement on page 2-15 that they "should not continue to rely on the short term regional energy market to meet its future capacity needs" is not only unsupported, but refuted by the facts on the ground – there is generally sufficient capacity, the region is integrating at a faster rate than envisioned in 2025 (the time of NWE's last supply plan), and the Company's near-term resource plans should explicitly incorporate this integration and defer any investments that might be better valued after seeing the economic picture when a more integrated region emerges over the next two to five years.

Response:

- Synapse's understanding of "the facts on the ground" is incorrect. NorthWestern's load is highly correlated to the regional load, and there is a growing capacity shortage in the region.
- Synapse's statement that there is "generally" sufficient generation capacity in the region shows a misunderstanding of the nature of resource adequacy. Resource adequacy programs are meant to ensure that sufficient capacity exists to meet peak loads. The E3 study and other analyses indicate that the region is currently short capacity or that it will be in the near-term.
- The notion that investments in generation capacity can be deferred until "a more integrated region emerges" is completely contrary to reality. This approach would ensure that it would be too late for NorthWestern to participate in that integrated market. That market will require NorthWestern to maintain a capacity margin, and building that margin will take time.

Lastly, as we note later in these comments, the best way to assess the value of potentially "deferring" any ratepayer-funded capacity investments (instead, capturing the value of the marketplace for NWE ratepayers) is to explicitly include a scenario in the final plan that contains capacity provision through short-term purchases (or capacity and/or firm energy) to allow for comparison to scenarios that would otherwise consider commencing build out of NWE resources in the near-term timeframe.

Response: This type of modeling would be based on the assumption that a sufficiently deep market is always available from which to procure capacity. NorthWestern fundamentally disagrees with this idea. It would also depend on the development of a forward curve for capacity out into the future, along with the correlation of capacity prices to energy and fuel prices. This would be an extremely difficult analysis. NorthWestern would not expect the results of this analysis to be valid or useful in a planning context.

NorthWestern addresses its impending participation in the EIM, but at best it is unclear if, or to what extent, its resource planning and portfolio analyses (Chapter 10) actually explicitly account for the transformed energy, ancillary service, and capacity market constructs that will exist in the region in 2021-2022 and beyond. NWE should ensure that its final plan describes in detail how the transformed constructs are explicitly represented in the modeling work that produces various estimates of net present value (NPV) for resource portfolios.

DRAFT

Bonneville Power Administration (BPA) is in the process of making a set of final decisions to join the CAISO EIM.[1] Avista announced it is joining the EIM in late April. The CAISO EIM will institute its dayahead enhancements in the fall of 2021[2] (those enhancements have been underway for some time).

Response: The day-ahead enhancements to be implemented in 2021 are for the CAISO full market, not the EIM. There has been no decision on whether to extend EIM to include a day-ahead market, though NorthWestern agrees that such development is likely.

It is likely that the day-ahead market improvements will be part of the EIM perhaps as early as 2022. NWE is joining the EIM in 2021 and expects that a market construct akin to an RTO will be in place by 2025 (page 5-10). These facts will directly, if not forcefully, bear on the nature, timing, cost and need for capacity resources NWE discusses in its draft plan.

Response: NorthWestern agrees that organized market development bears on the nature, timing, cost, and need for capacity resources. These facts increase the urgency for NorthWestern to add capacity given that organized markets require participants to meet resource adequacy requirements.

An RTO market construct implies the ability for participating utilities to effectively buy and sell capacity in a more efficient manner than currently exists in the somewhat balkanized environment of the Pacific Northwest (e.g., multiple balancing areas). The timing of these EIM developments is such that it is critical that NWE's action plan, and any possible procurement alternatives, explicitly recognize the changing landscape and not commit ratepayers to inefficient or costly investments in resources prior to knowing how the new market construct could allow NWE to reduce costs for its customers.

Response: An RTO will certainly include resource adequacy requirements, but it may or may not include a capacity market. The specifics of an RTO market design are not knowable at this time. However, it is a certainty that any such market will require load serving entities to carry a capacity planning margin. It would be colossally imprudent for NorthWestern to count on the development of a capacity market, to make the assumption that sufficient capacity will be available in that market at a lower price than NorthWestern could procure it in the long term, and to further assume that the rules of the RTO would allow unlimited short-term capacity purchases.

NorthWestern in its supply plan emphasizes a need for "flexible supply", and describes requirements for additional INC and DEC capacity, but it does not address how the different market construct will affect any need for INC and DEC requirements within the Company's service territory, compared to overall requirements across the EIM footprint. NWE acknowledges that the EIM allows for "reductions in flexibility reserves" and "sub-hourly dispatch benefits and savings" (page 5-5), but NWE should ensure its supply planning analyses explicitly incorporate a construct that aligns with the realities of the EIM in 2021 and 2022, and 2025 and beyond.

---

[1] See., e.g., April 26, 2019 BPA news piece, at https://www.bpa.gov/news/newsroom/Pages/Energy-ImbalanceMarkets-The-Grid-Mod-and-Strategic-Plan-connection.aspx.

[2] http://www.caiso.com/Documents/Presentation-Day-AheadMarketEnhancementsInitiativeUpdate-May22019.pdf.

DRAFT

Response: The flexibility requirements of the EIM in 2021 and 2022 are well defined. NorthWestern's planning is consistent with those requirements. The "realities" of 2025 and beyond are not as well defined, as markets evolve over time. NorthWestern expects that it may make adjustments in future planning cycles as more becomes known about the state and trajectory of market development.

For example, NorthWestern acknowledges that "the market itself addresses intra-hour balancing" (page 5-10) and thus concerns about NWE having sufficient INC/DEC capacity may be somewhat moot, since regional capability (reflecting regional supply and load diversity effects) will be the more salient factor.

Response: This statement shows a fundamental misunderstanding of the EIM and of NorthWestern's balancing needs. The EIM market efficiently *dispatches* generation in the market footprint. It is not a market for flexible capacity (or any other type of capacity). Regional capability is not the salient factor in the EIM. Each EIM entity must carry sufficient capacity to meet its own flexibility needs, so NorthWestern's own INC and DEC capabilities are critical to participation.

Does NorthWestern's draft plan address the capacity contracting changes and opportunities associated with joining EIM, in combination with the planned EIM changes (e.g., day-ahead enhancements) and that fact that neighboring utilities are also joining EIM? The final plan must directly and comprehensively answer this question, and address this critical regional construct that will be in place in two years and will affect both the scale and cost of purchase opportunities in the marketplace.

Response: NorthWestern agrees that further development of the EIM is likely, perhaps including the development of a day-ahead component. However, this is not a certainty, and in fact CAISO has not yet initiated a stakeholder process to make such a change (as will be required for a change of this magnitude). In any case, it is important to emphasize again that participation in an organized day-ahead market or RTO will not reduce or eliminate the need for NorthWestern to demonstrate resource adequacy. To the contrary, an RTO or other day-ahead market will codify the resource adequacy requirement. The development of these markets increases the urgency with which NorthWestern must address these needs rather than reducing it as Synapse seems to suggest.

2.2. Evaluating alternative resources

The Montana PSC requested that NorthWestern should comprehensively test the market in forthcoming resource plans to identify all potential resource options that could provide needed capacity services; NWE should assess, among other options, existing resources (uncommitted merchant generation at Colstrip and Hardin, hydro resources in Montana and the Pacific Northwest, Montana wind, demand response). The Company's resource plan should describe the potential value of these resources based on a comprehensive foundation of information obtained through the solicitation process via a request for information (RFI), with resource attributes modeled in PowerSimm.

NorthWestern issued an RFI in July 2018, designed to assess "potentially available resources for potential inclusion in capacity planning". While the RFI responses align somewhat with the slate of resources available in the modeling analysis, NWE has overlooked some key resource options. Table 1 below shows the number of responses to the Company's RFI by resource type in order of frequency, as compared to the number of resources NWE provided to its model. Solar plus storage, hydroelectric, internal combustion plus storage, coal, demand response, and wind plus storage resources are all absent from the available modeled resource slate. In contrast, NWE models three combined cycle resources when no relevant developers responded to the RFI. While the modeling exercise must not be perfectly aligned with an RFI, the dearth of renewable resource options and excess of natural gas-fired options available to the model seems incongruous.

Response:

- Resource planning cannot assume the availability of resources owned by other utilities or IPPs, nor can it assume the price at which these resources would be available.
- NorthWestern is in compliance with Montana RPS requirements, and renewable alternatives provide very little capacity contribution.
- Resource decisions will be made through the RFP process. The RFP will be open to existing resources as well as to combinations of renewables and storage.

Table 1. Number of July 2018 Request for Information responses versus available modeled resources by resource type

RESOURCE TYPE	RFI	MODELED
CT/ICE	6	5
BESS	5	2
Solar + Storage	5	0
Wind	4	1
Hydro	3	0
Coal	2	0
CT/ICE + Storage	2	0
DR/DSM	2	0
PV	1	1
Wind + Storage	1	0
CAES	0	1
CC	0	3
Geothermal	0	1
Pumped Hydro	0	1

Based on the RFI, Northwestern should include at least two paired storage resource options, and consider whether the abundance of gas-fired resource options influences the modeling exercise unreasonably.

Another critical deficiency of the analysis is that the analytical construct seemingly does not allow for direct purchase or procurement of market-based capacity resources. The "Automatic Resource Selection" (ARS) module does not include, for example, slice-of-system contracts for short-term capacity from those Pacific Northwest providers or utilities that may be long on capacity. The modeling is

DRAFT

"limited to resources with known and measurable operating characteristics" (page 10-2), and thus omits possible resource supply paths that include bilateral purchases of regional capacity, of varying duration. This is particularly important because the changing construct for energy and capacity markets in the region is such that short-term procurements to meet capacity obligations could be part of the portfolio of the most economically efficient (i.e., least-cost) means to meet customer load requirements.

Response:

- It is not appropriate from a planning perspective to assume that specific resources owned by others could be procured at a particular price, so slice-of-system contracts that are sold by northwest hydro owners were not included in the ARS runs.
- Any modeling of market-based capacity resources would require assumptions about 1) the availability of such resources, 2) the price of such resources for whatever short-term periods were considered, and 3) the particular operating characteristics of those resources. The speculation required for all of those assumptions would render the inclusion of these resources of little or no value to the process.
- NorthWestern expects to engage in short-term bilateral transactions into the foreseeable future. These transactions will provide value to customers, but they are not appropriate to consider from a planning perspective as a continuously rolling portion of the capacity portfolio. Short-term market transactions cannot be a replacement for long-term contracts or owned resources.

The portfolio approach in Chapter 10 does not allow for a direct comparison between the "Current" resource portfolio, which does not meet the presumed 16 percent planning reserve requirements, and other portfolios. This is a fundamental shortcoming of NorthWestern's modeling approach. The "Current" portfolio, when supplemented with market-price-based capacity resources, could demonstrate NPV levels that are lower than the other portfolios. NWE should define and develop a "Current Plus Market Capacity" scenario to allow for an apples-to-apples comparison to other scenarios.

The underlying approach to determining an optimal capacity expansion (such as represented with the "Unconstrained Expansion" portfolio) should allow for inclusion of market-based capacity resources.

Response: The portfolio suggested by Synapse is not a viable portfolio. It is not prudent for NorthWestern to treat reliance on a short-term capacity market as a viable alternative for its capacity needs. The NPV calculation of this portfolio would be dependent on the assumed market price of capacity for the 20-year planning horizon as well as the assumed availability of capacity in this market.

The Mid-term update to the Seventh Power Plan[3] presents updated, expected wholesale power prices at Mid-C, indicating essentially flat (real) prices through 2024 at that Pacific Northwest hub. Absent other information, this illustrates the critical importance of determining market price options to meet needs

[3] Northwest Power and Conservation Council, at https://www.nwcouncil.org/sites/default/files/7th percent20Plan percent20Midterm percent20Assessment percent20Final percent20Cncl percent20Doc percent20 percent2320193.pdf. February 2019.

for capacity and energy, as necessary. While it does not represent specific firm power prices to cover reserve needs, it does represent the broad competitiveness of the Pacific Northwest wholesale market and illustrates that NWE must include a rigorous review of market prices in its final resource plan.

Indications of Market Price Patterns from NWPPC Seventh Plan Mid-Term Assessment (March 2019)

Figure 3 - 6: Annual Wholesale Electricity Price Forecast from 2019 to 2038

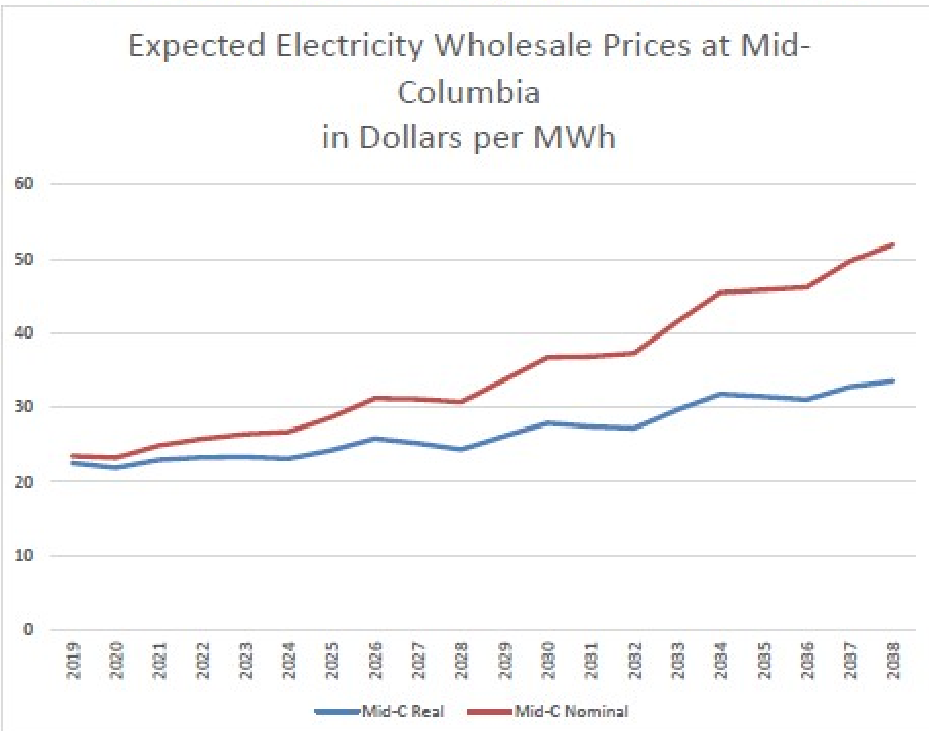
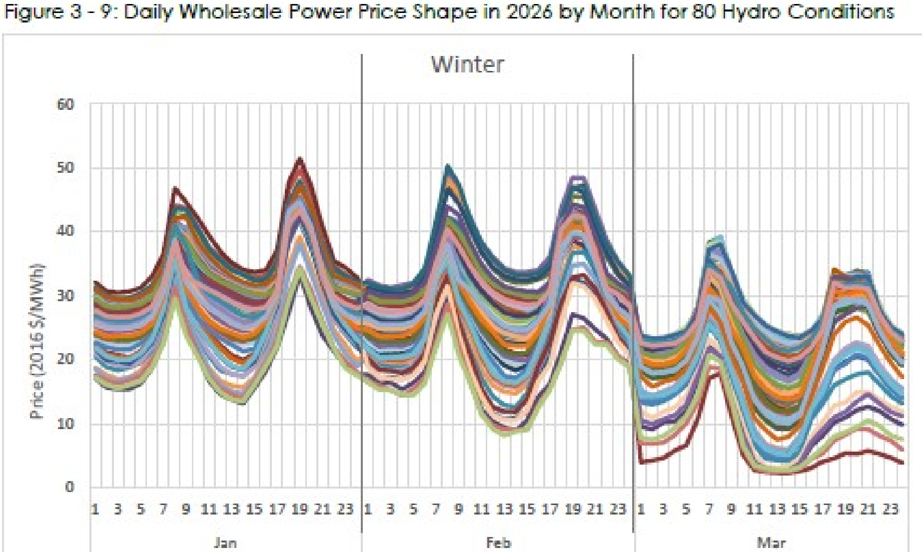


Figure 3 - 9: Daily Wholesale Power Price Shape in 2026 by Month for 80 Hydro Conditions



Source: Northwest Power Planning Council, Seventh Plan Mid-Term Assessment, March 2019.
https://www.nwcouncil.org/sites/default/files/7th percent20Plan percent20Midterm percent20Assessment percent20Final percent20Cncl percent20Doc percent20 percent232019-3.pdf

Response: This issue is addressed in Chapter 11.

The resource optimization aspect of the Action Plan should contain a more comprehensive description of how NWE will approach maximizing the potential for peak period contribution from run-of-river (or other) hydro assets that currently have limited INC/DEC ratings (as seen in Table 4-4) and peak load contribution ratings that in most cases are significantly below their Facility Capacity ratings (Table 4-1).

Response: The opportunities for increasing the peak period contribution for run-of-river facilities are very limited. They are described as run-of-river precisely because their licenses and/or physical characteristics prevent them from being used for peaking, INC, or DEC. The hydro facilities that do have flexibility are limited by river flows, storage capacity, and license requirements. Since flows are not at their highest during the peak load months, the peak load contribution of our hydro resources will always be significantly lower than their capacity ratings.

While we will continue to look for opportunities to improve the dispatch of our portfolio, including the hydro resources, we do not believe that there is enough remaining untapped flexibility in the hydro system to warrant specific mention as an action item.

The "Emerging Technologies" chapter includes reference to demand response and distributed energy resources. The final plan should more comprehensively describe how these two technologies can reduce peak period requirements, including estimation of the peak-reduction MW value potential. NWE should explain why the ADMS software should not be employed, or deployed, as soon as possible rather than "within the next five years" to maximize its potential to capture peak period demand reductions.

Response: Both demand response and DERs can provide additional capacity to the electric system. One through the targeted shedding of load and the other through the addition of generation. Either one, or both, can provide peak capacity additions or support during system disturbances. The ADMS software together with an additional module/software can be used to control these resource types. The base ADMS software is being deployed at this time and that deployment is expected to be complete during the first quarter of 2020. In parallel to that deployment a distribution control center is being stood up. The control center staff will operate the system, and over the course of 2 to 3 years be fully trained to exercise centralized control through this system. Today the distribution system is operated regionally and until the transition to full central control is completed the ability to control DERs centrally will be limited. This is why the document states "within the next five years."

2.3. Evaluating sources of uncertainty

In its comments on the 2015 Plan, the Commission noted various sources of uncertainty that it felt were not sufficiency evaluated by NorthWestern. Those include: resource costs, capacity contributions, implications of transitioning to RBC regulation, integration requirements for wind and solar, load forecasts and impacts of behind-the-meter distributed generation (including their seasonality, capacity value, and energy production), natural gas price forecasts, carbon regulation, infrastructure costs (natural gas and electric), regional EIM participation and associated impacts on liquidity in energy and capacity markets, and development of a regional ISO.

NorthWestern calls out certain of these risk variables (resource costs, capacity contributions and integration of wind and solar, transition to RBC, and net metering impacts) on page 2-8 of the Draft Plan and discusses the ways in which they are addressed in the document and its various underlying studies. NWE examined alternative scenarios to test the uncertainty associated with other risk variables. With respect to carbon costs, NWE modeled three trajectories of carbon dioxide (CO_2) pricing in PowerSimm—a base CO_2 price of zero and two alternatives in which CO_2 pricing begins in 2028 ("Carbon" portfolio) and 2025 ("High Carbon" portfolio), respectively. NorthWestern modeled most of its resource portfolios with a base natural gas price forecast but also examined one "High Natural Gas Prices" portfolio.

Response: This issue is addressed in Chapter 11.

NWE references "market risk" (page 11-1); however, it is not clear from any of the modeling scenarios that the monetary cost of the risk has been estimated. As noted in these comments, NWE should explicitly incorporate a scenario that procures capacity from the market to allow for a direct estimation of this alternative in comparison to the other scenarios modeled.

Response: See previous responses to issues raised in Section 2.2.

It is not clear that NorthWestern evaluated any alternative scenarios for uncertainty around capacity credits, and the capacity credit the Company gives to potential new solar and wind resources is prohibitively low in the PowerSimm modeling. New solar resources are credited for none of their nameplate capacity (0 percent) and new wind resources are credited for just 1.9 percent. This does not align with the historical contributions of wind and solar resources in the NorthWestern service territory, nor with industry standard assumptions around capacity crediting. Treatment of effective load carrying capacity (ELCC) for renewable resources must account for different values based on a summer peak need and a winter peak need, both of which occur on NWE's system. Solar PV generally does not contribute to winter peak needs, but it does contribute to summer peak needs; wind has a much higher contribution for winter peak needs than for summer peak needs. While a zero-capacity credit for solar in winter months may be reasonable, NorthWestern should allow intermittent resources to provide different capacity requirements on a monthly basis, so that their benefit in summer peak months is recognized.

Response: This issue is addressed in Chapter 11.

In Chapter 4 of the draft report, Northwestern states that resource peak load contribution is determined based on production during historic peak load periods, as demonstrated in Table 4-1. Table 4-1 lists historical peak load contributions for some existing wind resources (as high as 20 percent) but lists the peak load contribution as "TBD" for newer renewables. The modeling output workbooks provided to Synapse indicate that the default capacity credit for all existing solar and wind resources without sufficient historical data is 10 percent and 5 percent respectively. Thus, a credit of 0 percent and 1.9 percent for new generic resources does not align with historical output.

This capacity credit also conflicts with general industry understanding of solar and wind operation. In CAISO, the 2018 solar and wind ELCCs ranged from 0-47.5 percent by month and resource, with an average annual ELCC for both around 22.6 percent. While the CAISO system differs substantially from the NWE service territory, their monthly construct for ELCC represents the paradigm for these credits. The Navigant NEM study described in Chapter 4 assigns a 6.1 percent capacity contribution factor to behind-the-meter solar resource in the NorthWestern service territory, and points to the need for a more comprehensive analysis across the region.

Response: This issue is addressed in Chapter 11.

This low or zero ELCC definition effectively restricts any buildout of solar and wind resources within PowerSimm. If these resources are not credited for providing any capacity to the grid, the model will not choose to build them regardless of their competitive low cost in the market. This is borne out in the scenario analysis, where no renewable resources are built in any optimized scenario except the "No Carbon Builds" portfolio. Additionally, a low capacity credit can inflate the cost of portfolio renewables by overbuilding resources with low firm capacity representations at a high cost.

Response: This issue is addressed in Chapter 11.

2.4. Stakeholder involvement

In Comments dated February 2, 2017, the Commission made several observations relating to NorthWestern's stakeholder process. Resource planning rules encourage NWE to utilize an independent advisory committee throughout its planning process, which the Company has named the Electric Technical Advisory Committee (ETAC). The Commission noted that ETAC membership was limited and that NorthWestern should do its best to expand membership and the type of organization represented on the Committee. Current ETAC membership includes representatives from The Northwest Energy Coalition, Montana Consumer Counsel, Montana Department of Environmental Quality, Montana Environmental Information Center, Natural Resources Defense Council, Northwest Power and Conservation Council, University of Montana – BBER, District XI Human Resource Council, a Consumer at Large, and the Montana PSC and its consultants. While ETAC membership has expanded beyond environmental organizations, per the Commission's suggestion, membership remains quite small. It does not yet include resource developers, per the 2017 recommendation of the PSC, and still excludes many of the organizations that submitted comments in Docket No. N2015.11.91 on the 2015 Plan or subsequent status reports filed by the Company.

Response: This issue is addressed in Chapter 11.

NorthWestern held 19 ETAC meetings and workshops during the period from February 2, 2017 (the date of the Commission's Comments) and the release of the draft plan on March 5, 2019, which is a marked increase from the five meetings held during the development of the 2015 Plan. Notably, however, NWE's final ETAC meeting was held on November 28, 2018, which was several months prior to the completion of the portfolio modeling done in PowerSimm. The ETAC members thus did not have the opportunity to review and comment on any of the results of that portfolio modeling prior to the release of the Draft 2019 Plan. Absent this review, which would include the ability to examine input assumptions and to ask questions of NorthWestern, it is impossible for ETAC members to confirm that the PowerSimm modeling supports the Company's conclusions around an optimal resource portfolio and action plan.

Response: This issue is addressed in Chapter 11.

Related to this was the Commission's 2017 request that NWE provide increased transparency around the modeling process and give legitimate stakeholders access to the PowerSimm model. The Company has provided Synapse, as consultants to the PSC, access to the PowerSimm model's user interface via remote access and allowed us to view input and output variables through this interface. Synapse is the only party to have such access to PowerSimm and access to the capacity expansion resource portfolio modeling runs was not granted until after the Draft Plan had been published by NWE. There was no opportunity for Synapse or any other ETAC member or stakeholder to suggest alternative model runs that should be done by NWE and Ascend or to evaluate the adequacy of the use of the PowerSimm model or the subsequent conclusions about resource adequacy and resource procurements presented in the Draft Plan. This creates the sort of "information asymmetry that undercuts the legitimacy of NorthWestern's resource-planning exercise" that the Commission warned about in 2017.[4]

Response: This issue is addressed in Chapter 11.

2.5. Competitive procurement process

The Company intends to procure any new resources through the RFP process, soliciting competitive proposals from a variety of resources. NorthWestern has stated that the resources procured through

[4] Montana Public Service Commission Comments in Response to NorthWestern Energy's 2015 Electricity Supply Procurement Plan. Docket No. N2015.11.91. February 2, 2017. Page 17.

these competitive solicitations may be those identified in the Draft Plan, but that it is more likely that resources not identified or modeled will be those that are actually acquired by the Company (page 11-3).

NorthWestern references a possible solicitation for capacity on pages 11-3 to 11-4, calling out many of the resources referenced by the Commission in its comments. The listing explicitly includes "solar generation with storage" and "wind generation with storage". NWE should explain if this listing is implying that solar PV or wind resources alone (or, in combination to support both summer and winter peak contribution) would not be eligible to participate in such a solicitation. The final plan should be very clear which resources or resource combinations are eligible, and should strive to be as all-inclusive as possible, as resources available from respondents may not contain the full breadth of technical attributes NWE or the region requires for overall system reliability. An "all source" or equivalent resource solicitation should be considered to allow providers of resources to offer their most attractive products, without having to necessarily offer a portfolio of resources.

The Action Plan should clarify, or explain otherwise, that demand response and battery storage resources are eligible for participation in any solicitations that may be issued.

The MT Commission noted in its comments on the 2015 Plan that a previous RFP done by NorthWestern unreasonably established a minimum service period of 20 years. Any RFP that follows the Final 2019 resource plan should allow for resource procurements of less than 20 years.

Response: Competitive solicitations will allow for resources of less than 20 years. This issue is also addressed in Chapter 11.

2.6. Forecast horizon

In the December 2017 supplemental comments, the Commission discussed the recent evolution in the Western market that has led to changes in the operations at existing generators and expressed skepticism around utility resource investments that subject customers to costs and risks today for benefits that are projects to occur at some future date. The PSC requested that the planning horizon in PowerSimm be truncated to 15 years and that cost recovery be modeled to occur within this timeframe. In the Draft Plan, NorthWestern presented the following two resource portfolios: 1) "Short Term Current," which models the resource portfolio as it currently exists, does not add any new resources, and limits the planning horizon to 15 years; and 2) "Short Term Base," which adds new resources based on a constrained Automatic Resource Selection, but includes the 15-year planning horizon and capital recovery period requested by the MT PSC.

The resource selection under the "Short Term Base" portfolio adds 784 MW of RICE generation and 85 MW of new natural gas-fired combustion turbines (CT) over the course of the 15-year planning period, which is very similar to the "Base" model, which adds 882 MW of RICE generators in the first 15 years of the 20 year analysis period. The "Short Term Base" portfolio is shown in Figure 1 and the "Base" portfolio is shown in Figure 2, below.

Figure 1. "Short Term Base" resource portfolio

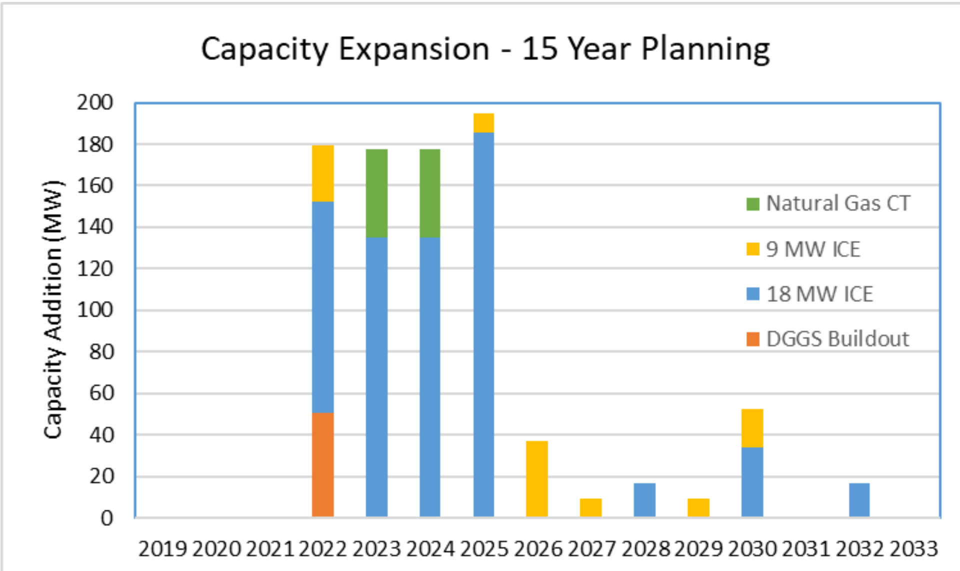
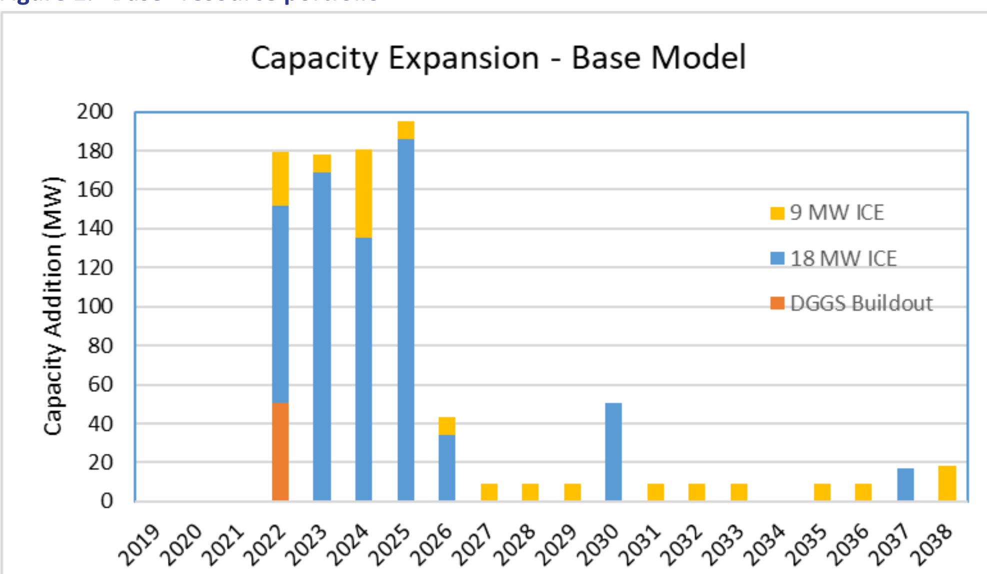


Figure 2. "Base" resource portfolio



The intent of the Commission's comments and recommendations regarding a 15-year planning horizon and cost recovery is to protect customers against NorthWestern's acquisition of particular assets that may become stranded at some future date. In modeling the 15-year planning horizon with cost recovery, NWE is following the letter of the Commission's recommendation. Given that the asset mix does not change from the "Base" portfolio to the "Short Term Base" portfolio, however, and the Company provides no context or analysis justifying the results with respect to the PSC concerns, the Company is not following with the spirit of the Commission's recommendation.

Response: This issue is addressed in Chapter 11.

2.7. Transmission

NorthWestern expresses concern that if no additional generation is built in the region after Colstrip retires, the assets might be less useful and the import capacity to NWE's system could be limited. However, current queueing data on NWE's OASIS, summarized below in Table 2, indicates more than 5,000 MW of active queue requests for wind, solar, hydro and gas on the system. The final plan should assume a high likelihood of full capability of the transmission assets that allow for imports into the NWE territory from the broader Pacific Northwest systems.

Table 2. NWE OASIS generation queue data – April 29, 2019

Status	Active				
Sum of Winter Output	Generating Facil T				
In Service Date	Gas Fired	Hydro	Solar	Wind	Grand Total
11/30/2017			9		9
9/1/2018				750	750
12/31/2018				80	80
7/1/2019	150				150
10/1/2019				40	40
12/31/2019				75	75
5/15/2020				80	80
6/1/2020			2		2
10/31/2020				160	160
12/1/2020			460		460
12/30/2020		450			450
12/31/2020				80	80
9/21/2021				1,500	1,500
12/31/2021			80	800	880
10/31/2022				300	300
Grand Total	150	450	551	3,865	5,016

Source: NWE OASIS interconnection queue, "active" status, accessed 4/29/2019.

DRAFT

Response: As discussed in the ERSP, NorthWestern is concerned about having sufficient capacity available to serve our load. In February of 2019, during our all-time peak loading day, non-dispatchable energy (i.e. wind) was at near 0 MW output at the time we most needed it. Of the resources that you list, 150 MW out of the 5,016 MW would be considered dispatchable. Put another way, over 4400 MW of the generation in the interconnection queue noted above is for intermittent, non-dispatchable energy resources that cannot be counted on to serve peak load needs. NorthWestern's need is for dispatchable capacity that can be deployed when needed.

NorthWestern provides information on energy import flows into their system on peak summer days in 2018 (pages 6-12/13). While NWE indicates that there was "no available transmission capacity to import electricity from BPA" during the peak hours, the graphs nevertheless demonstrate that significant levels of energy were flowing into the system. NWE should make clear in the final plan if it is asserting that there is a shortage of peak-day energy availability for flows into its system from adjacent regions; and if so, then the Company should more comprehensively describe the nature of the scheduling process and the advance reservation of transmission that allowed for a maximum of roughly 750 MW of imports on August 10, 2018 (Figure 6-4).

Response: The fact that there was 750 MW flowing into the system and ATC at BPAT was zero does illustrate the point that is being made. With ATC at zero from the most liquid trading point on the system, the likelihood of failure to meet load under a single contingency such as the loss of another generation resource, loss of a transmission line or loads greater than anticipated increases.

Either the system can import 750 MWh during a peak hour in August or it cannot, but both of those circumstances cannot simultaneously be true. It appears that NWE utilized capacity that was available to import 750 MW during the peak hour on August 10, 2018, and that fact appears to support the more general notion that import capacity is available during summer peak days. NorthWestern should also include winter peak day analogs to this discussion in its final plan.

Response: See previous response. NorthWestern has also added a winter peak day in the Transmission Chapter.