Review of NorthWestern's 2023 IRP

Michael Goggin, Grid Strategies

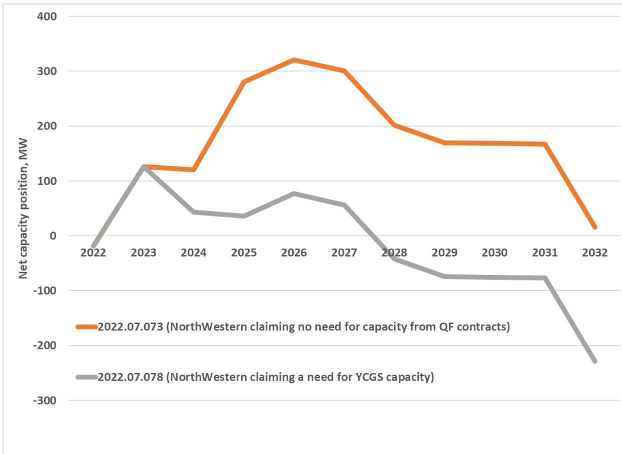
August 2023

These comments identify significant flaws in the reliability and economic analysis NorthWestern presents in its 2023 IRP. Correcting these flaws shows that NorthWestern does not need additional fossil and/or nuclear capacity, and that renewable and storage resources can better provide NorthWestern ratepayers with cost-effective and reliable power. In particular, NorthWestern drastically overstated the cost of renewable and storage resources, and understated the value of federal tax credits for these resources.

Reliability issues

-NorthWestern has sufficient capacity for at least the next decade. NorthWestern's own charts in the IRP confirm that there is no need for additional capacity until 2032, and show a large capacity surplus in both winter and summer through 2028.[1] In other proceedings before the Commission, NorthWestern has confirmed its large capacity surplus in arguing that the avoided cost for capacity payments for Public Utility Regulatory Policies Act (PURPA) Qualifying Facility (QF) resources should be zero, on the basis that NorthWestern does not need additional capacity until 2032. As shown in Figure 1 below, NorthWestern has presented the Commission with drastically different views of its capacity position, depending on whether NorthWestern is proposing to add owned assets to its rate base (Docket 2022.07.078) or opposing QF resources on which it will not earn a rate of return (Docket No. 2022.07.073).

[1] IRP Volume 1, at 7



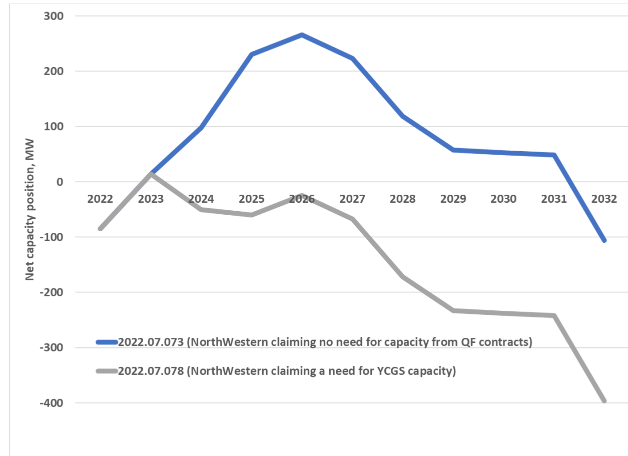


Figure 1: NorthWestern's claimed summer (left) and winter (right) net capacity in two dockets[2]

NorthWestern's capacity need analysis in the IRP does not count the large amount of QF capacity that is proposed to come online over the next several years.[3] The IRP documents that NorthWestern's interconnection queue contains 905 MW of proposed QF renewable capacity, including a mix of wind and solar resources that can help meet both winter and summer peak demand periods, as well as 242 MW of storage co-located with those renewable resources.[4] If a significant share of those QF resources come online, which NorthWestern and the Montana Public Service Commission (MPSC) can control because they help determine the fate of contracts with QF resources, that would further improve NorthWestern's capacity position, particularly because of the much higher capacity accreditation for renewable resources under WRAP rules. Accounting for these resources would potentially eliminate the need for capacity supply from Yellowstone County Generating Station (YCGS), the proposed acquisition of Colstrip capacity from Avista, and the large additions of gas capacity that are proposed in most of its IRP scenarios and sensitivities. Notably, the one IRP scenario that assumes all proposed QF projects are built calls for no additional gas capacity beyond YCGS.[5] Charts in Volume 2 of the IRP confirm that if the capacity contributions of QFs that have been approved by the MPSC are included, then NorthWestern has no need for capacity through 2035, and an even larger surplus farther into the future if potential QF projects that have started negotiations with NorthWestern are included.[6]

NorthWestern also notes in the IRP that the apparent need for capacity arises in the 2030s due to "capacity contracts that expire," so if those contracts are extended that will further push out the need for additional capacity.

-NorthWestern understates the capacity contributions of wind and solar. In its IRP modeling NorthWestern understates the capacity value provided by wind and solar, claiming that "Wind and solar

---

[2] For more background see the written testimony of Mr. Goggin in NorthWestern's recent rate case, Docket 2022.07.078, filed December 19, 2022, describing NorthWestern Intervenor Testimony of Steven Schmitt opposing capacity payments for QFs due to NorthWestern's lack of capacity need in Docket No. 2022.07.073, at 9

[3] "The views in this section exclude QFs that do not have a signed agreement with NorthWestern. This approach captures the fact that there is significant uncertainty associated with QF schedules and also that some do not advance to completion. Chapter 8 and Volume 2, in contrast, explore NorthWestern's capacity positions with proposed QFs included." IRP Volume 1, at 48

[4] IRP Volume 1, at 72

[5] IRP Volume 1, at 75

[6] IRP Volume 2, at 22-23

are capable of providing low-cost energy but are generally not available to provide capacity when customers need it most, like after sunset on the coldest winter days in December and January. Wind is typically only producing about five percent of its maximum capability on those days (5% of nameplate capacity)."[7] This claim is contradicted by NorthWestern's own analysis of wind and solar capacity accreditation under Western Resource Adequacy Program (WRAP) rules, which shows that wind offers a winter capacity value of 31% and summer capacity value of 13%, while solar offers a 30% capacity value in summer.[8] NorthWestern even notes that wind's winter capacity accreditation of 31% under WRAP rules is markedly higher than the 13% it assumed in its IRP modeling. As a result, NorthWestern's IRP analysis missed how a portfolio of wind and solar resources provides large contributions toward meeting demand during both winter and summer peak periods.

Even more concerning is that NorthWestern plans to bias its future resource selection against wind and solar resources due to this understatement of their capacity value. In Volume 2 of the IRP, NorthWestern discloses that in future Requests For Proposals ("RFPs"), it intends to require wind or solar resources to be paired with battery storage.[9] This requirement is unnecessary for two reasons. First, wind and solar resources offer significant capacity value on their own, with wind providing large winter capacity value and solar providing significant capacity value in the summer, as noted above. Second, storage resources are also economic on their own following passage of the Inflation Reduction Act (IRA) a year ago, under which battery resources no longer needed to be paired with renewable resources to be eligible for the federal Investment Tax Credit (ITC). As NorthWestern even notes in Volume 1 of the IRP, "Energy storage now qualifies for the ITC as a stand-alone project where storage previously had to charge from a renewable resource to qualify for the credit. It is for this reason that hybrid storage projects were not considered as candidate resources."[10] Batteries are highly modular so they can be deployed at more optimal points on the grid where they can help alleviate transmission congestion or provide local reliability services like voltage support, or where "energy community" bonus tax credits are available, as discussed later in our comments. Thus, requiring bids for renewable resources to be paired with storage is unnecessary and likely to result in uneconomic bids.

-The Northwest is expected to have large capacity surpluses for the foreseeable future as WRAP reduces the need for capacity, so NorthWestern should conduct an RFP for capacity purchases. NERC's Long-Term Reliability Assessment shows the Northwest region has large surpluses through the end of this decade, and potentially even longer if planned resource additions materialize.[11] The regional capacity surplus is also increasing as WRAP reduces reserve margins and increases resources' capacity accreditation by tapping into regional diversity in electricity supply and demand patterns.[12] NorthWestern's last RFP for capacity purchases was in 2020,[13] so NorthWestern should conduct a new RFP to assess the availability and pricing of capacity offers in the market, particularly after WRAP has begun to reduce regional capacity needs.

Obtaining market-based information on the availability and pricing of capacity purchases would also address NorthWestern's objection to considering those resources in the IRP. As noted in Volume 2 of the IRP, Montana Public Service Commission staff requested that NorthWestern model capacity purchases as

---

[7] IRP Volume 1, at 88
[8] IRP Volume 1, at 69
[9] IRP Volume 2, at 18
[10] IRP Volume 1, at 63
[11] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf at 95
[12] IRP Volume 1, at 16
[13] IRP Volume 1, at 41

a selectable resource in the IRP modeling, but NorthWestern rejected that request because "Capacity contracts are not widely available and NorthWestern is not certain that such contracts will be available in the future."[14] The Commission should insist that NorthWestern obtain market-based information prior to reaching a conclusion regarding the availability and pricing of capacity resources, and use that market-based information to model those resources in the IRP.

-Updated duration analysis shows short-duration resources like batteries provide significant capacity value towards meeting peak net load, though NorthWestern still ignores the major role of imports in helping to meet long-duration peak demand events. NorthWestern has updated its duration analysis to look at the frequency and duration of high **net** load events (net load = load minus renewables), rather than just periods of high load. This updated analysis shows a much shorter duration of peak net load needs, with all events in which net load exceeded 1,150 MW lasting 4 hours or less, versus 8 hours in the duration analysis for load alone. This indicates that at least initial additions of batteries with 4-hour duration offer essentially their full nameplate capacity as capacity value, as they have sufficient duration to fully meet the current peak net load events. After meeting those current peaks, larger additions of batteries would also make a significant contribution to meeting many of the longer-duration net load periods, as explained in more detail at the end of this section. This updated net load analysis confirms the point we made in our comments on NorthWestern's last IRP that accounting for the contributions of renewables would shorten the duration of capacity need, allowing batteries to more cost-effectively meet the need for capacity than proposed gas additions like YCGS.

However, NorthWestern's analysis is still flawed as it ignores other components of supply, like imports, that shorten the duration of peak net load periods. Many of the long-duration peak net load events identified in NorthWestern's analysis are interrupted by large amounts of imports. The IRP itself notes that imports met 38-50% of load during NorthWestern's peak summer and winter demand periods in 2022.[15]

Imports access geographic diversity in the timing of peak load across Northwest utilities. Given Montana's geographic distance from Northwest load centers, there is typically large weather and climate diversity that results in NorthWestern not experiencing peak demand at the same time. For example, Winter Storm Elliott did not significantly affect load centers in the Pacific Northwest, allowing NorthWestern to meet over 47% of its load with imports.[16] At minimum, due to time lags in the movement of weather systems, geographic diversity greatly shortens the period when most utilities are simultaneously experiencing peak demand. This further demonstrates the value of imports for reducing the duration of peak net load periods.

Imports also benefit from regional diversity in net load due to geographic diversity in wind and solar output patterns. By tapping into geographically diverse wind and solar resources across significant parts of the West, imports help ensure supply will be available even if NorthWestern's renewable output is low. Solar and wind output are negatively correlated because they tend to produce the most during different seasons and times of day, so one is likely to be available if the other is not. Correlated conventional generator outages are also an important determinant of capacity need, and generator outages due to extreme weather are typically short-lived and result from localized weather events, so tapping geographic diversity through imports mitigates their impact as well.

---

[14] IRP Volume 2, at 10
[15] IRP Volume 1, at 51
[16] *Id.*

As noted above, NorthWestern's net load duration analysis shows that initial additions of batteries offer full capacity value. Larger additions of batteries would also make a significant contribution to meeting many of the longer-duration net load periods, with only gradual declines in capacity value as the penetration of batteries increases. Higher penetrations of solar energy, and to a lesser extent wind energy, also increase the capacity value of batteries. By producing a large amount of energy during the early to mid-afternoon, solar tends to reduce the duration of system peak net load periods, allowing battery or demand response resources with limited duration to better contribute throughout the peak demand period. This complementary relationship is shown in Figure 2 below.[17] NREL has calculated that on the U.S. power system, up to 28 GW of 4-hour batteries can be installed before their capacity value begins to decline. However, that figure doubles to around 60 GW once solar penetrations reach 10%.[18]

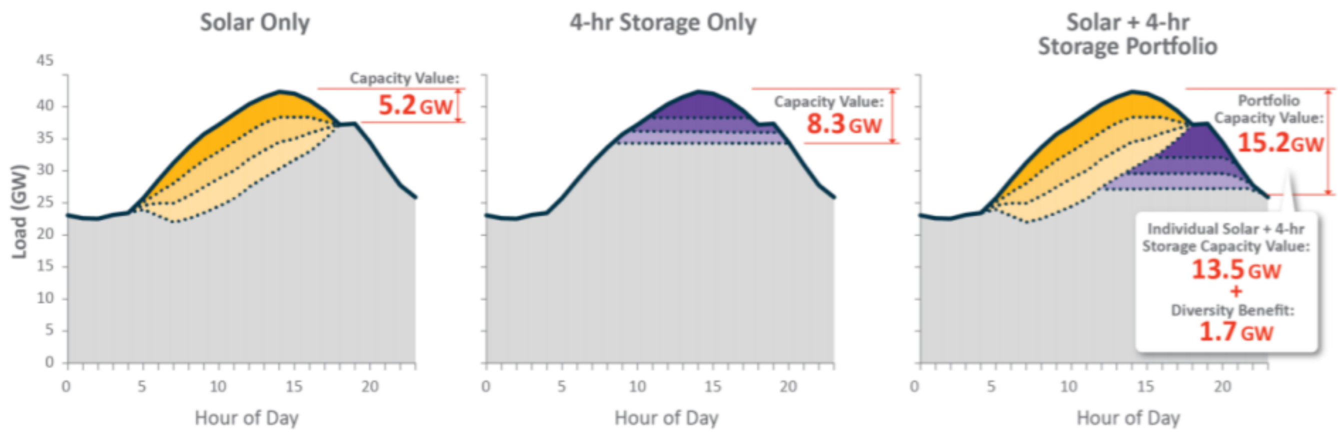


Figure 2: Capacity Value Synergies between Solar and Storage

Finally, we continue to note the concern expressed in our comments on the last IRP that NorthWestern's duration analysis does not follow standard utility practice. NorthWestern's method is not used by any other utilities, likely due to the methodological shortcomings discussed above. Effective Load Carrying Capability and Loss of Load Probability analyses are the typical and appropriate methods for accounting for capacity value and resource adequacy, and those methods account for the capacity contributions of imports and renewable resources.

-NorthWestern ignores correlated outages that reduce the capacity value of fossil resources, and particularly gas generators. NorthWestern's IRP claims that "NorthWestern is committed to the Colstrip acquisition and to completing YCGS. Both of those energy sources are proven to perform in extreme weather events and can be dispatched according to load and price signals."[19] However, the chart on the next page of the IRP, which is replicated below, shows a drop of around 100 MW in thermal generation (shown as the gray area at the bottom of the chart) during the peak demand and peak pricing period on December 22, 2022.

---

[17] Nick Schlag, et al., *Capacity and Reliability Planning in the Era of Decarbonization*, at 6 (Energy and Environmental Economics Aug. 2020), *available at* https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.

[18] https://www.nrel.gov/docs/fy19osti/74184.pdf

[19] IRP Volume 1, at 45

Figure 6-10. December 2022 Cold Weather Event – Load and Prices

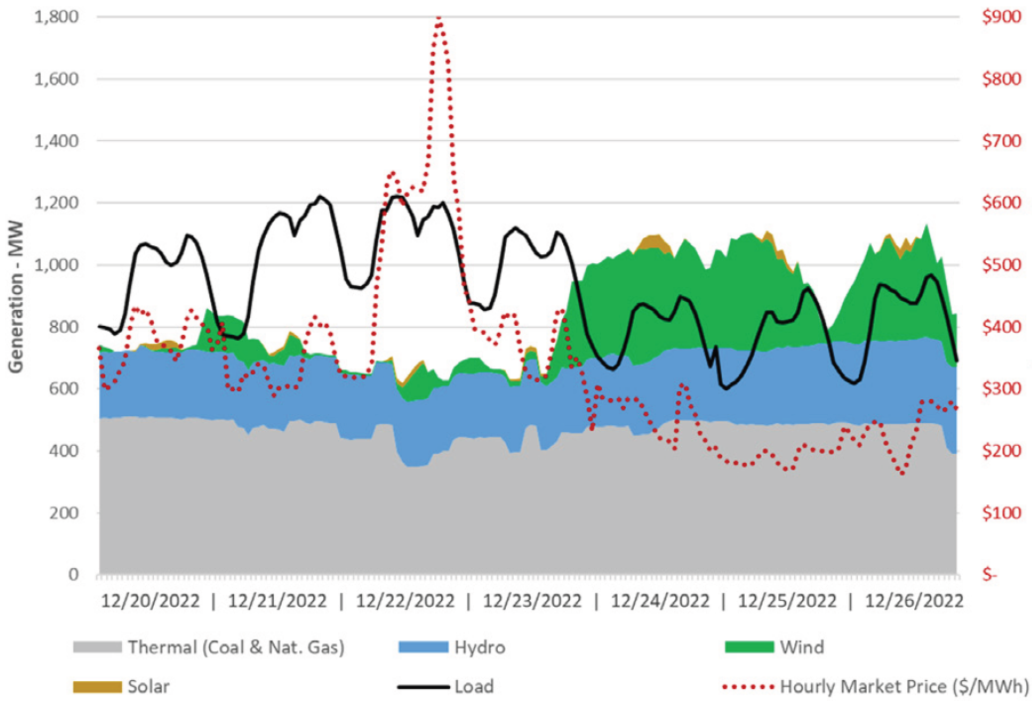


Figure 3: NorthWestern IRP chart showing ~100 MW drop in fossil generation as demand and prices spiked on December 22, 2022

EPA hourly generation data indicates this drop resulted from the loss of nearly 100 MW of generation across units 1A, 1A, 3A, and 3B at the gas-fired Dave Gates Generating Station beginning in the late morning on December 22 and lasting until late that night,[20] as shown in the chart below. It is not clear if this drop in gas generation just as demand and electricity market prices spiked was due to an equipment failure, the loss of gas supply, or if gas spot market prices simply made fuel supplies uneconomic. Regardless, this event shows the reliability and economic risks of increasing NorthWestern's dependence on gas generation, and directly contradicts NorthWestern's claim that gas generators are "proven to perform in extreme weather events."

[20] Data available at https://campd.epa.gov/data/custom-data-download

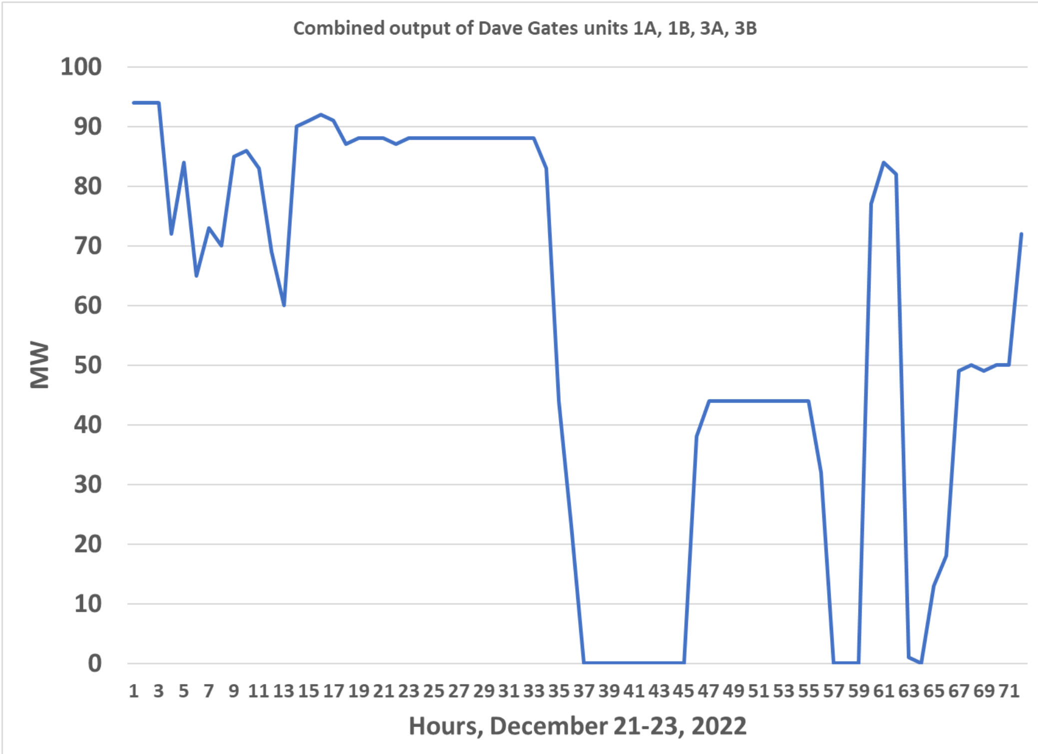


Figure 4: EPA data for Dave Gates units 1A, 1B, 3A, and 3B total output on Dec 21-23, 2022

Those risks are confirmed by repeated instances of widespread gas generation failures in multiple regions during recent extreme weather events, due to gas wellhead freeze-offs, generator equipment failures and derates, and pipeline disruptions. These events include Winter Storms Elliott and Uri in 2022 and 2021, the 2018 Bomb Cyclone, the 2014 Polar Vortex, and the 2011 Southwest outages, each of which resulted in rolling blackouts or near-misses. The economic and reliability risks of gas dependence are not just confined to extreme weather events. The Northwest experienced widespread and long-lasting gas supply disruptions after the 2018 Enbridge/Westcoast Energy BC pipeline failure,[21] as did the Southwest following the 2015-2016 Aliso Canyon gas storage leak.[22]

-Renewables and storage resources can help address any local voltage concerns resulting from the retirement of Colstrip. NorthWestern claims that retiring Colstrip will require the installation of reactive power devices to regulate voltage.[23] NorthWestern's estimated cost of $20-30 million for these devices is small relative to the ongoing cost of operating Colstrip and does not justify continued operation of Colstrip. Moreover, the need for these devices could be reduced or eliminated if a diverse mix of wind, solar, and storage resources, such as the resources offered by pending QF projects, are allowed to interconnect and deliver their generation via the Colstrip Transmission System. Renewable and storage

[21] https://www.nwcouncil.org/2021powerplan_british-columbia-pipeline-rupture-and-fire/

[22] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/november-2-2020-results-of-econometric-modeling.pdf

[23] "NorthWestern's analysis concluded that imports from off-system resources cannot control voltage in the same way that the generation at Colstrip can control voltage, and an immediate loss of Colstrip would create high voltage problems on the transmission system. An installation of reactors would be required to mitigate this high voltage." IRP Volume 1, at 48

resources are now required by FERC to match the contributions to reactive power and voltage control provided by conventional generators.[24]

NorthWestern's Colstrip retirement analysis only examined scenarios in which large amounts of wind energy were used to replace Colstrip, and found that additional reactive power and voltage regulation would be required during periods of low wind output.[25] If NorthWestern had used a more realistic and diverse mix of wind, solar, and storage resources to replace Colstrip, instead of only wind, it could have reduced or eliminated those concerns. This is partially because a portfolio of wind, solar, and storage resources has more consistent output, with solar and wind tending to produce at opposite times of the day and year, and storage filling in when they are not available. In addition, solar and storage resources can be configured so that their power electronics can use grid power to provide voltage and reactive power support, even when the plant is not producing real power. For example, the power electronics of solar plants can be configured to provide reactive power and voltage support at night, at a much lower cost than installing new reactive power devices.[26]

-NorthWestern's IRP modeling shows the much higher value storage resources offer relative to gas resources due to their fast sub-hourly flexibility. NorthWestern's IRP includes PowerSIMM modeling of sub-hourly market revenues that different types of new resources could realize through Western Energy Imbalance Market (EIM) sales. This analysis shows that storage resources offer about 2-3 times as much sub-hourly flexibility value as combustion turbine or internal combustion engines, with the value premium for storage resources increasing over time with West-wide renewable penetrations. The value premium for storage is around $50-100/kW-year in most years, which for reference accounts for most if not all of the cost of building a combustion turbine.[27]

Given the superior value batteries provide for sub-hourly flexibility and the large expansions of battery capacity planned elsewhere in the EIM footprint, NorthWestern's planned gas generators may not be able to compete with those batteries to provide sub-hourly flexibility. Because it is not clear what if any penetration of batteries outside of Montana was assumed in the PowerSimm modeling, NorthWestern may be overestimating the profits gas generators can earn in the EIM market.

-NorthWestern overstates the challenges of accommodating renewables' variability. NorthWestern's IRP cherry-picks a single event during which wind output on its system was highly variable.[28] NorthWestern does not attempt to establish that this event posed a concern for reliability, and a cursory review of the data confirms that it did not. First, Department of Energy data show that the ramp up in wind output occurred as demand was ramping up in the late afternoon peak demand period, and then wind output ramped down as load was dropping off that evening.[29] Because the ramp in wind output was highly correlated with demand, it actually reduced net load variability on NorthWestern's system, reducing the

---

[24] https://ferc.gov/sites/default/files/2020-06/RM16-1-000.pdf

[25] IRP Volume 2, Appendix G, at 102-104

[26] https://cdn.sma.de/fileadmin/content/www.sma-america.com/docs/Q%40NIGHTWP-UUS134511P.pdf?v=1660809118&_ga=2.42114413.915951628.1690554640-246618966.1690554640 In particular, see page 9: "The investment costs of the option "Q at Night" are significantly lower in comparison to the costs for compensation plants. In particular, the savings are considerable compared to dynamic compensation plants."

[27] For example, see MISO's estimated cost of new entry for a combustion turbine of $80-110/kW-year (converted from $/MW-year by dividing by 1,000) at page 11 https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf

[28] IRP Volume 1, at 18

[29] NorthWestern hourly demand and wind output data available at https://www.eia.gov/electricity/gridmonitor/knownissues/xls/NWMT.xlsx

ramping required of other resources relative to what would have been required for demand alone. Second, wind energy forecasting accurately predicts changes in wind output up to several days in advance, so NorthWestern and other grid operators can plan market purchases and the commitment and dispatch of other resources around expected changes in wind output. Third, even in instances in which wind or solar output ramps increase net load variability, that impact is greatly mitigated through EIM transactions that tap into geographic diversity in both load and wind and solar output patterns across the West, reducing ramping needs by around 60%.[30]

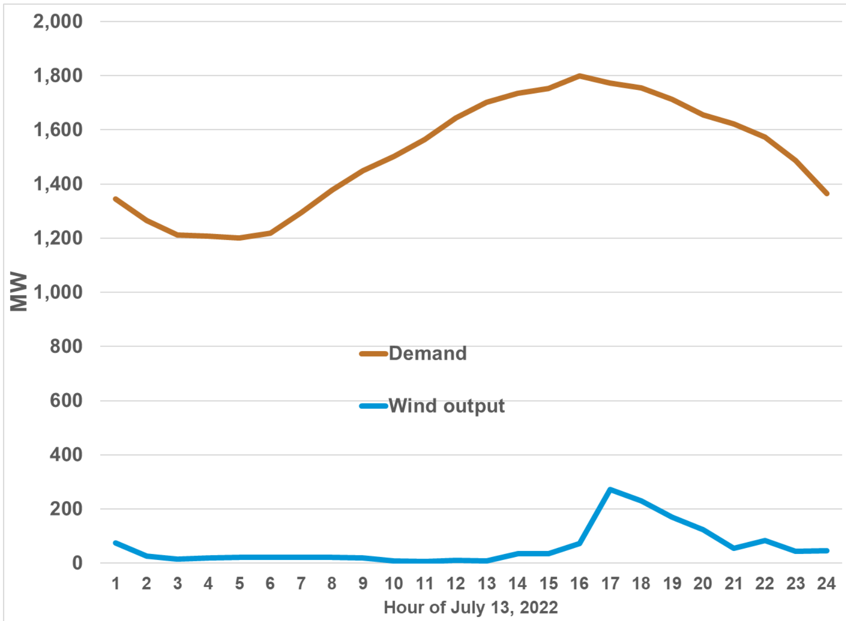


Figure 5: DOE data showing NorthWestern demand and wind output on July 13, 2022

Economic issues

-NorthWestern's assumed capital costs for wind, solar, and battery costs are drastically higher than the widely-used costs in the National Renewable Energy Laboratory's Annual Technology Baseline (NREL's ATB), as shown in Table 1 below. NorthWestern's cost overestimates, as well as its large understatement of the value of the Production Tax Credit (PTC) for wind and solar discussed below, strongly bias the IRP modeling against the selection of renewable and battery resources and towards conventional resources, and overstate the cost of scenarios with greater renewable and battery deployment. NorthWestern's high battery cost estimate may also be shifting deployment from batteries to pumped hydro storage in the IRP modeling.

Table 1: NorthWestern's renewable and battery cost assumptions are 38-68% higher than NREL's

Resource	NREL cost estimate 2025/26,[31] $/kW	NorthWestern cost estimate for 2025/26, $/kW[32]	NorthWestern overstates cost by x%
300 MW Solar	$1,204	$1,662	38%

[30] https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q4-2022.pdf, at 35
[31] https://atb.nrel.gov/electricity/2023/index
[32] IRP Volume 2, Appendix H, at 112

100 MW Solar	$1,204	$1,864	55%
300 MW Wind	$1,172	$1,764	51%
100 MW Wind	$1,172	$1,970	68%
50 MW 4-hour battery	$1,436	$1,984	38%

NorthWestern offers cost assumptions for solar and storage resources entering service in 2025 and wind resources that begin operating in 2026,[33] so these costs are compared against NREL ATB cost estimates for resources installed in those years. For 300 MW solar or 50 MW battery resources entering service in 2025, and 300 MW wind resources entering service in 2026, NorthWestern assumes capital costs are $1662/kW for solar, $1764/kW for wind, and $1984/kW for 4-hour batteries. NorthWestern assumes even higher capital costs of $1,970/kW for a smaller 100 MW wind project and $1,864/kW for a 100 MW solar project.

-NorthWestern's analysis greatly understates the value of the clean energy tax credit extensions and expansions provided in the Inflation Reduction Act. In a small print footnote to a table buried in the last appendix to Volume 2 of the IRP, NorthWestern discloses that it modeled the wind and solar Production Tax Credits (PTCs) by simply reducing the capital cost of these resources by 30%, apparently reflecting the value of the 30% Investment Tax Credit (ITC).[34] However, in Volume 1 of the IRP, NorthWestern explains that the PTC is much more valuable than the 30% ITC for solar resources, noting that "Solar qualifies for the PTC and the ITC, but most utility scale plants will fare better with the PTC."[35] The wind PTC is even more valuable relative to a 30% ITC, given wind plants' significantly higher capacity factor and generation.

Simple analysis demonstrates that the PTC is significantly more valuable for both wind and solar than the 30% reduction in capital cost that NorthWestern assumed. Specifically, the net present value of the wind PTC is 96% more valuable than the 30% cost reduction NorthWestern assumed for a 300 MW project, and the solar PTC is 58% more valuable than NorthWestern's assumed 30% cost reduction for a 300 MW project. Said another way, the net present value of the PTC offsets 59% of NorthWestern's assumed capital cost of a 300 MW wind project and 47% of the assumed cost for a 300 MW solar project, significantly greater than the 30% reduction assumed by NorthWestern.

Table 2 shows the combined effect of NorthWestern's flawed assumption about the value of the renewable PTC and its high starting cost estimates for wind, solar, and battery resources. The combined effect of these errors is that NorthWestern overstates the cost of solar by a factor of 3, and the cost of wind by a factor of 10. The combined effect of these flaws massively skews NorthWestern's resource selection and causes it to overstate the cost of scenarios that use large amounts of renewable resources.

Table 2: NorthWestern vs. NREL cost estimates, after accounting for tax credits

Resource	NREL cost estimate with tax credit value, $/kW	NorthWestern cost estimate with 30% ITC, $/kW[36]	NorthWestern overstates cost by x%
300 MW Solar	$415	$1,163	280%

[33] Volume 2 at 98
[34] IRP Volume 2, Appendix H, at 112
[35] IRP Volume 1, at 63
[36] IRP Volume 2, Appendix H, at 112

100 MW Solar	$415	$1,305	314%
300 MW Wind	$133	$1,235	929%
100 MW Wind	$133	$1,379	1037%
50 MW 4-hour battery, 30% ITC	$1,005	$1,388	38%

The analysis to convert the net present value of the revenue stream from PTCs received over the first 10 years of the project's operation to an equivalent up-front ITC value uses the same 6.92% discount rate that NorthWestern assumed based on its Weighted Average Cost of Capital.[37] The analysis also uses the midpoint of NorthWestern's estimates for wind capacity factors of 40-45% and solar capacity factors of 20-25%,[38] which are likely conservative estimates given the quality of NorthWestern's renewable resources and continued technology improvements for wind and solar. This analysis also accounts for the facts that 1. the PTC is indexed at NorthWestern's assumed 2% inflation rate going forward and 2. the PTC is 27.75% more valuable because it is after-tax revenue, while income from other energy generation is taxed at the 21% federal and 6.75% Montana corporate tax rates.

To be conservative, two potential 10% bonus adders to the federal renewable and storage tax credits that were created by the Inflation Reduction Act are not accounted for in our analysis. NorthWestern's analysis did not account for the energy community and domestic content bonus credits either, even though large parts of Montana are designated as energy communities due to their history of fossil fuel production and coal generation.[39] For the ITC, these credits each increase the credit by 10 percentage points above the standard 30% credit, so a project receiving both bonus credits would be eligible for a 50% ITC. This could significantly reduce the cost of battery storage and potentially solar resources in many parts of Montana below NorthWestern's assumption that only a 30% tax credit is available.[40] A battery receiving a 50% ITC, and with the corrected NREL costs shown above, would be half as costly as NorthWestern assumes using its cost estimate and its assumed 30% ITC. For the PTC, each of these bonus credits increase the tax credit by 10% above the current $27.5/MWh value, so a project receiving both bonus credits could generate $33/MWh in tax credits. NorthWestern's analysis also does not appear to account for the value of tax credit transferability, which greatly reduces the cost of monetizing the federal tax credits for entities without sufficient tax liability. If these provisions were accounted for, the cost of renewable and storage resources would be further reduced below the estimates presented above.

-NorthWestern's IRP includes a scenario in which Colstrip is retired in 2025 and only renewable and storage resources can be added, though NorthWestern did not include sufficient renewable resources to cost-effectively meet energy and capacity needs. NorthWestern's claim that this scenario is more costly than its base case[41] is partially attributable to the incorrect cost assumptions for renewable and battery resources and NorthWestern's underestimate of the value of federal tax credits, as discussed above, but also because NorthWestern did not include sufficient renewable generation in the replacement portfolio. The resource additions in all sensitivities for this IRP scenario are almost entirely storage

---

[37] IRP Volume 1, at 97
[38] IRP Volume 1, at 61
[39] https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d
[40] NorthWestern reveals it assumes only a 30% tax credit is available in the IRP at 46: "However, under the IRA, certain build-specific factors may result in investment tax credits of 6 to 30%. While these tax credits would reduce overall wind and solar costs, the YCGS plant remains the most economical option."
[41] IRP Volume 1, at 78

resources, with only 100 MW of wind additions and no solar additions,[42] resulting in a portfolio that is energy deficient and dependent on higher cost market purchases than the low-cost energy provided by wind and solar generation that receive federal PTCs. As noted above, NorthWestern assumes 100 MW wind projects have an even higher cost than the already exorbitant cost estimate for 300 MW wind projects. A more balanced replacement portfolio would include a mix of wind and solar to provide both winter and summer capacity, and replace the energy provided by Colstrip with wind and solar generation that is highly cost-effective in part due to federal PTCs.

-NorthWestern's assumed coal price is too low. NorthWestern explains that for modeling the cost of coal for Colstrip, "The PowerSIMM model used the annual prices agreed upon in the contract until the expiration date of the contract in 2025. After the contract expiration, coal prices are assumed to escalate at 2% annually to align with future expectations for long-term inflation."[43] However, the current contract pricing excludes the more than 18% inflation that has occurred since 2020, which has particularly affected equipment and labor costs, so it is unreasonable to assume those cost increases are not recovered when the contract ends in 2025. This assumption significantly understates the cost of continuing to operate Colstrip beyond the year 2025.

-YCGS is included in all scenarios, depriving the Commission and stakeholders of information about whether it is truly economic or needed. NorthWestern has not yet given the Commission the opportunity to evaluate the prudence of that investment, which is required for costs associated with the generator to be put into rates. As a result, it is essential that NorthWestern expand its analysis to include at least some scenarios that do not include YCGS, which would provide the Commission and stakeholders with important information about its cost and reliability impact relative to alternatives.

-NorthWestern's proposed reliance on Small Modular Reactors (SMRs) to replace Colstrip in some scenarios is expensive and risky, as these reactors have not been commercially deployed at scale. In Volume 2, NorthWestern discloses that the assumed $3,600/kW capital cost for SMRs was provided by SMR developer X-Energy,[44] while Aion Energy provided the cost assumptions for all other technologies. A single commercial entity with a vested interest in selling its product is not a credible source of cost assumptions. In fact, the Department of Energy's capital cost estimate for SMRs is $8,349/kW,[45] more than twice NorthWestern's assumption.

---

[42] IRP Volume 1, at 74
[43] IRP Volume 1, at 65
[44] IRP Volume 2, at 15
[45] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf, at 2