TAMING THE PEAKS

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to meet infrequent peaks in demand.
But it can lower the peaks instead – and save customers money –
which is precisely what many other utilities are already doing.

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Table of Contents

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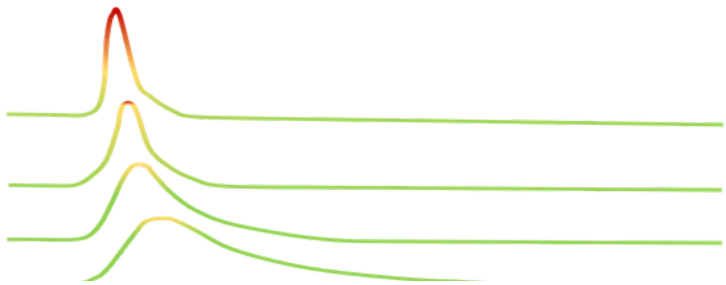

INTRODUCTION – PEAK ELECTRICITY IS EXPENSIVE ELECTRICITY

The electricity system in the United States is built around peaks in demand, which are relatively short periods when electricity use is greatest. For example, the most common type of peak demand in the U.S. occurs on weekdays during hot summer weather. In the late afternoon or early evening hours, people return from work and turn on their air conditioners. The widespread and simultaneous use of electricity during weather that is already driving high demand creates peak conditions.

When the demand for electricity is high, utilities pay more to buy electricity and they pass those costs on to their customers. The grid was built to supply sufficient electricity during peak demand which means the grid only operates at its full capacity for about 90 hours per year, which is about 1% of the time. The other 99% of the time, power plants and transmission lines operate well below their full capacity.

Region-wide in the Western U.S, peak demand tends to occur on hot summer weekdays in the late afternoon and early evening. Montana also experiences peaks in electricity demand during cold weather, and in these cases there are typically two peaks per day, one in the morning and another in the evening.

Anything that causes peaks in demand to climb higher will drive the construction of new power plants or other infrastructure, even if they're only needed infrequently. NorthWestern Energy's approach to system planning is to let the peaks arrive when and where they may, and then build new infrastructure to meet the peaks and pass those increased costs on to customers.

Because NorthWestern Energy earns a 9.65 to 10% return on equity from its customers on its electricity infrastructure, the company is incentivized to build more infrastructure, rather than design a more efficient system.

Building more capacity to meet peaks leads to high ratepayer costs, because much of the system goes unused most of the time. A peaker plant that's used for 90 hours per year will have an extraordinarily high cost per megawatt hour, and that cost is borne by ratepayers.

That's why most utilities and utility commissions work to manage peaks. There are many tools to lower peak demand, and most utilities have programs to do just that. NorthWestern Energy is well behind its industry peers when it comes to managing peak demand. In fact, programs that are standard throughout the industry, such as demand response and energy storage, remain uncharted territory for NorthWestern Energy. Furthermore, the company has dismissed and mischaracterized many of the strategies already being used successfully elsewhere. Ultimately, NorthWestern's lack of a strategy to manage peak demand leads to an overbuilt system and higher bills for ratepayers.

As data centers seek to bring very large loads online, managing electricity demand becomes even more critical, and fortunately there are excellent tools to manage large loads. These strategies have immediate benefits, such as improved reliability, lower costs, and a more efficient system.

This report presents many ideas for ways to lower peak demand. Each section contains case studies and successful examples from around the country that are already saving both energy and money. The report also summarizes NorthWestern's current or proposed policies, which stand out in contrast to improvements happening at other utilities. Montana can learn from progress elsewhere, and this report aims to help that process.

KEY STRATEGIES AND TAKEAWAYS

1 GRID UTILIZATION: MAKING BETTER USE OF WHAT WE ALREADY HAVE

- Outside of peak events, there is generally spare capacity available on the grid.
- This capacity can be put to use to add new loads, as long as they are flexible and can avoid peaks.
  - Data centers have a large potential to be part of the solution. They have several options for temporarily reducing electricity consumption, such as pausing model training or shifting tasks to data centers in other regions.
  - Data centers can also switch to their own, on-site energy storage during peaks.
  - One study showed that in Bonneville Power Administration's territory, if new large load customers were curtailed just 0.25% of the time – 22 hours per year – the system could add 1.6 GW of new load without building new capacity.
- Improved grid utilization in the U.S. could yield 20 to 30% more electricity sales each year and save ratepayers $11 billion to $17 billion every year.
- Grid-enhancing technologies like advanced conductoring can help carry more electricity on existing power lines.
- Currently, utilities are incentivized against grid utilization because they get a return on investment for building new assets.
- Grid utilization efforts may have to be required by regulators. State regulators can ask utilities to measure their current grid utilization, and create incentives for higher levels of use.

2 BATTERY STORAGE: STORING CHEAP ELECTRICITY FOR USE DURING HIGH-VALUE TIMES

- Batteries tend to save money because they charge when the grid is experiencing low demand and electricity is relatively inexpensive. Batteries often charge with renewable energy during off-peak times which is also inexpensive as well as nonpolluting. Batteries discharge during the peak times of day when electricity is most expensive. The familiar adage of “buy low, sell high” is an important role of battery energy storage.
- The price of battery energy storage fell 93% between 2010 and 2024, from $2,634 per kWh in 2010 to $197/kWh in 2024.
- In areas with high-quality wind or sun, renewables with storage are cost-competitive with new combined cycle gas power plants in the U.S.
- Because of the advantages offered by batteries, many utilities in the U.S. have already deployed batteries to manage peaks in electricity demand.
- The Public Service Company of New Mexico is a standout example because it added large amounts of new battery storage and designed interconnection policies that minimize the waiting time for new projects to connect to the grid. Residential electric bills have risen by only 3% over five years, despite the buildout of new, clean energy infrastructure.
- In Wyoming, a new Meta data center will be partially powered by solar and batteries. The large load service agreement between Meta and Black Hills Energy allows the utility to tap into the data center’s own, on-site backup generation during systemwide peak events. According to Black Hills Energy, this agreement will defer the construction of an entire power plant.
- In Minnesota, Xcel Energy will be installing small batteries distributed throughout the grid. The program will consist of 200 MW of storage, in the form of batteries that are 1-3 MW in size. The project is intended to relieve constraints on the grid, but in a localized and highly targeted manner.
- NorthWestern Energy currently has no batteries on its system.
- NorthWestern Energy put unnecessary, illogical constraints on batteries in its modeling for the 2026 IRP. These constraints downplay the advantages, flexibility, and potential of batteries. NorthWestern Energy’s analysis does not instill confidence in its understanding of battery energy storage.

3 DEMAND RESPONSE: SHIFTING THE TIMING OF PEAK LOAD SAVES MONEY AND REDUCES POLLUTION

- NorthWestern Energy currently has no demand response program and no plans to use demand response to lower peak electricity demand. Multiple energy experts, regulators, and members of the public have advised NorthWestern Energy to improve demand response and demand side management.
- NorthWestern Energy hired a consulting firm to assess potential ways to use demand response to lower peaks. The report showed that NorthWestern Energy could lower peak demand by 121 MW in the summer and 45 MW in the winter. For context, the Yellowstone County Generating Station has a capacity of 175 megawatts.
- NorthWestern Energy appears unmoved by these potential savings, and did not include any demand response programs in its 2026 IRP, even when the Public Service Commission asked it to do so.
- Most utilities already use demand response to lower peaks, and several in our region are lowering their peak demand by 8 to 10%.

- Customer-owned, small scale battery storage is another potentially large opportunity that's being used by other utilities in our region.
- Demand response for data centers and other large load customers offers potentially large savings and this strategy is already being rolled out around the U.S.
- NorthWestern Energy is courting multiple data centers, but it has not developed a program for flexible loads from data centers.

4 INTERREGIONAL TRANSMISSION: CONNECTING AREAS WITH EXCESS SUPPLY TO AREAS OF HIGH DEMAND

- Transmitting electricity between regions is an efficient way to solve peak demand, because peaks in electricity use typically don't happen at the same time in different regions, and excess generation also occurs at different times in different places.
- Long-distance transmission lines that connect neighboring regions can carry electricity from locations with spare capacity to the places that need it most, making the grid more cost-efficient for everyone.
- The North Plains Connector is a 3,000 MW transmission line that will connect the west-coast bound Colstrip transmission line at Colstrip to two locations in North Dakota. Multiple studies have found that the North Plains connector will bring reliable electricity to its co-owners and it can be counted on as a steadfast capacity resource.
- Because it connects three different sections of the U.S. grid, the North Plains Connector will provide energy and capacity during both summer and winter capacity critical hours.
- NorthWestern doesn't account for the added capacity it will get from the North Plains Connector in its modeling or forecasts. Instead, NorthWestern intends to fill its capacity needs by building more power plants, which raises costs for ratepayers.
- In contrast, nearby utilities are considering the North Plains Connector as a capacity resource. Avista is evaluating a 300 MW share of the connector, and Avista's 2025 IRP shows the North Plains Connector as a capacity resource in its planning.
- Portland General Electric has committed to a 600 MW share of the North Plains Connector. Portland General Electric's resource forecasts reflect the full 600 MW of capacity from the North Plains Connector.
- Utilities and system planners should consider interregional transmission to be a capacity resource so that ratepayers get the full benefit of these projects. A proper accounting of the benefits of transmission is needed to prevent overbuilding of new generation resources.

5 ELECTRICITY MARKETS: ROBUST, ORGANIZED TRADING BETWEEN UTILITIES MAKES THE SYSTEM CHEAPER AND MORE RELIABLE

- Buying and selling of electricity between utilities brings substantial benefits of reliability, a "right-sized" generation fleet, less curtailment of renewable energy, and lower costs.
- Regional electricity markets help coordinate trade between various utilities in our region.
- NorthWestern Energy is part of the Western Energy Imbalance Market, which organizes trading in real time or near real time. Participating in the Western Energy Imbalance Market has provided NorthWestern with $223.8 million in benefits since it joined in June 2021.
- For longer planning horizons, day-ahead markets help utilities plan for weather, expected demand, and the output of their own fleet.
- NorthWestern is considering joining one of two day-ahead markets, the Extended Day-Ahead Market (EDAM), or Markets +. Either market would bring benefits to NorthWestern Energy and its ratepayers, but EDAM appears to hold more advantages.
- An interconnected Western market can save nearly $1.2 billion each year. EDAM taps into a large fleet of low-cost renewable energy generation, as well as an expansive network of traditional generation sources. The larger the market, the greater the benefits to ratepayers.
- Multiple studies have found that EDAM offers much larger potential for savings, compared to Markets+.
- NorthWestern Energy should not only conduct a careful analysis of both options, but should also release the results to the public and incorporate the analysis into its IRP.

1.GRID UTILIZATION

MAKING BETTER USE OF WHAT WE ALREADY HAVE

KEY TAKEAWAYS

- Outside of peak events, there is generally spare capacity available on the grid.
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- Grid utilization efforts may have to be required by regulators. State regulators can ask utilities to measure their current grid utilization, and create incentives for higher levels of use.

One frequently hears about the overcrowded and stressed grid, but here's a number that may be surprising: The grid is only used at about half of its overall capacity.

The U.S. electricity system is purposefully overbuilt so that it can handle peak events, even though they only occur 50 to 200 hours per year, according to Pier LaFarge, the co-founder and CEO of Sparkfund. In the Western grid, peak demand occurs for about 90 hours per year. That leaves excess capacity that could be put to use the other 98-99% of the time, without building a single power plant or transmission line.

Grid utilization is the simple concept of maximizing the use of existing infrastructure. Instead of building new infrastructure, we can get more use from the assets that are already in place and paid for.

Optimizing the use of power plants, energy storage, and transmission sidesteps the need to build new projects, allows for quicker load growth, and saves ratepayers money because more revenue is generated with the same amount of equipment. The concept is simple, but it requires a shift in thinking.

> ***Better grid utilization is one of the fastest, most practical levers states can pull to reduce power bills while supporting economic growth.***
> **Ian Magruder**, Utilize Coalition

Imagine a young family that just had adorable twins, and everyone wants to come and visit them. To accommodate the growing guest list, the family could build an addition to their home, even though many of the rooms would sit empty most of the time. Since it would take many months to build the project, relatives would have to delay their visits until the new space was built. Of course, this would be an expensive solution and a lot of work would go into accommodating a relatively infrequent event. Lastly, the new addition might not be needed for too long, and all the extra space risks becoming a stranded asset once the twins become teenagers and are therefore less interested in family visits.

Alternatively, the family could keep their existing house as-is and find solutions to avoid overcrowding. They could schedule family visits across different times, or use the homes of other nearby family members to house overflow guests. With this solution, guests could come and visit right away, and no new construction expense would be needed.

Most of us would choose the latter scenario. But many utilities would prefer the former.

A TALE OF TWO (FICTITIOUS) UTILITIES: ONE LOWERED PRICES, THE OTHER EARNED MORE REVENUE

A modeling study by the Brattle Group compared two storylines using a hypothetical, mid-sized, investor-owned utility that needs to serve a growing electricity demand. This hypothetical utility is somewhat similar to NorthWestern Energy, by pure coincidence.

One storyline explored the idea of maximizing the assets already in place. Instead of building new power plants and transmission lines, the utility was able to get more electricity use from its existing infrastructure. This was possible by finding locations and times when the grid is running well below peak demand, and adding new load in ways that used some of this spare capacity.

Because the existing system was able to serve more customers without building new infrastructure, prices went down for all users. New industries could be brought on more quickly, and more jobs could be added to the local economy. By getting just 10% more use out of its electricity system, rates dropped by 3.4%.

Next, consider the utility that prefers to keep doing things the way they always have. To meet new loads, new assets were built. Ratepayers' bills went up to pay for the new construction. It took twice as long to get new projects connected to the grid and allow new businesses to operate. The overall utilization of the system did not improve.

Guess which scenario earned more revenue for the utility? The second one. That's because utilities are guaranteed return on investment for assets they own – they are incentivized to build more infrastructure. And this leads to an overbuilt, inefficient, and expensive system.

Thus, grid utilization strategies may have to be mandated rather than voluntary.

When a utility faces the choice of building new infrastructure or making better use of what it already owns, the goal of shareholders is likely the opposite of what ratepayers would want. If grid utilization is mandated, then a utility can justify those efforts to its shareholders. But without regulations, it's a harder case to make. Regulators are essential to protect the interests of ratepayers.

SIMPLE SHIFTS SAVE EVERYONE MONEY

The Brattle Group report outlines some of the basic strategies of grid utilization.

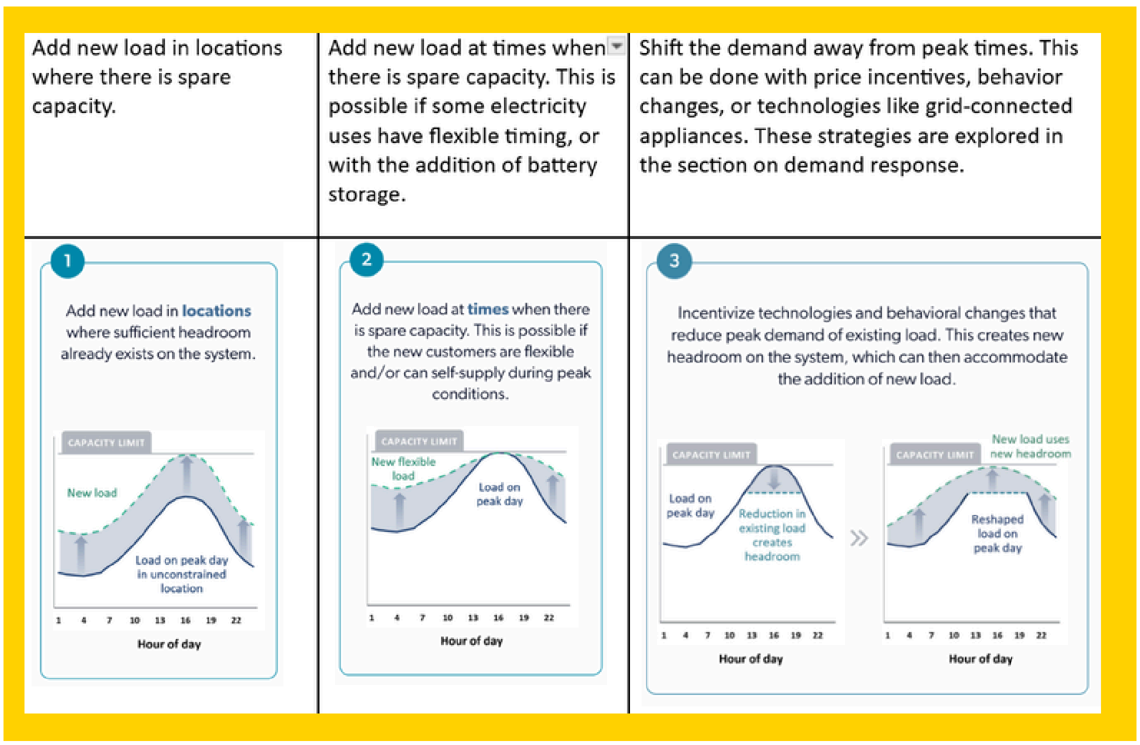


Image from *Brattle*, The Untapped Grid

The report authors estimated that improved grid utilization in the U.S. could yield 20 to 30% more electricity sales each year. These increased revenues would lower customer bills and save ratepayers $11 billion to $17 billion every year.

TOOLS TO GET MORE OUT OF WHAT WE ALREADY HAVE

Diving in a little deeper, the Brattle Group report lists multiple strategies to improve system utilization:

- Battery energy storage
- HVAC controls and smart thermostats
- EV charging controls and/or vehicle-to-grid connectivity
- Smart meters and smart panels
- Time-varying electricity rates
- Flexible interconnection policies that allow the utility to prescribe limits to larger load customers
- Data center flexibility, especially when data centers have their own, on-site electricity supply
- Targeted energy efficiency where it provides the greatest value to the grid
- Grid-enhancing technologies, such as advanced conductors, power flow controllers, and real-time dynamic line ratings, which allow more electricity to pass through a given line when conditions are safe to do so
- Improved system planning, so that utilities can target new upgrades for the highest-value constraints rather than overbuilding capacity

Demand response and energy storage are key strategies for grid utilization, and they are discussed in detail elsewhere in this report.

Improving system utilization doesn't avoid new projects altogether, but it can help utilities identify where new projects can unlock the largest benefits and therefore the biggest value.

There is one important downside to grid utilization, which is that it can create new demand for power plants that are expensive to operate, polluting, and/or inefficient. This raises costs and imposes a larger pollution burden on the public. If NorthWestern Energy were to pursue a grid utilization strategy, it must be done in a way that prioritizes less expensive and cleaner resources as a top priority.

Learn more: The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability, The Brattle Group, 2026

VIRGINIA IS THE FIRST STATE TO REQUIRE UTILITIES TO MEASURE THEIR GRID UTILIZATION AND FIND WAYS TO IMPROVE

The first recommendation in the Brattle Group report is for utilities to measure their grid utilization. Virginia is the first state to require utilities to do just that. A new law signed in April 2026 requires Dominion Energy and Appalachian Power to collect data on grid utilization and report it to regulators. Utilities also have to look for ways to increase grid utilization "through the deployment of non-wires alternatives."

The legislation defines "non-wires alternatives":

1. energy storage resources
2. customer-owned or customer-financed capacity resources
3. utility-owned or utility-contracted distributed generation resources
4. virtual power plants
5. flexible transmission and transmission static synchronous compensators
6. synchronous condensers; (which reduce losses from transmission lines)
7. power quality monitoring equipment installed at the point of interconnection for all customers with a measured or contracted demand of 25 megawatts or greater.

Virginia is home to scores of data centers, and is facing rising demand, spiking prices, and ratepayer dissatisfaction. This legislation is the first to ask utilities to find ways to accommodate new load without building more power plants and transmission. Ultimately, the measure is expected to save ratepayers' money.

Learn more: Virginia is becoming the nation's grid utilization test bed
Virginia to utilities: Do more with the existing power grid

THERE'S ROOM FOR IMMEDIATE GROWTH ON THE EXISTING GRID

The U.S. grid already has room to add more capacity without building new power plants – but the catch is that the new load needs to be slightly flexible so they can avoid existing peaks in demand. Analysts at Duke University found that nearly 100 GW of new, large loads could be added while maintaining reliability and affordability.

The study authors looked at different regions of the U.S. and determined how much "headroom" exists in each area. In other words, how much load could be added without building new capacity. The authors also calculated how much flexibility would be required from the new load – how many hours each year the new load would have to slow or stop using electricity in order to avoid adding to a peak event.

The study did not examine NorthWestern Energy's territory but it did look at Bonneville Power Administration (BPA), which covers much of the Pacific NorthWest, including parts of Montana. BPA could add 2.3 GW of new load, as long as that new load can be curtailed around 1% of the time to avoid the highest peaks of demand. That translates to 88 hours of slowing or stopping electricity use per year, typically in events around 2 hours long.

If new customers were curtailed just 0.25% of the time – 22 hours per year – the system could add
1.6 GW of new load.

Note that these curtailments are intended for large loads like data centers, not residential customers or businesses.

During those peak hours, large load customers have several options to reduce their electricity use:

- Use on-site battery backup
- Shift workload to other facilities
- Slow or pause high-intensity computing tasks
- Manage summer afternoon cooling with on-site batteries.

Ratepayers would benefit from adding new, flexible loads to the grid because more revenue can be gained from the existing system, which lowers the cost of each megawatt-hour generated.

Why would a company agree to shut down its energy use occasionally? The big tradeoff is that it could build its project much faster, avoiding years of waiting for new power to be designed, approved, built, and connected to the grid. In the race to scale up AI and build more data centers, getting to market sooner offers a substantial competitive advantage. Case in point, Google designed two new data center projects with flexible energy needs, because the company can slow down machine learning workloads during peak grid events.

Learn more:
Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems, Nicholas Institute for Energy, Environment & Sustainability, Duke University, 2025

Data Center Demand Flexibility, Energy Innovation, 2025

GRID-ENHANCING TECHNOLOGIES CAN EXPAND TRANSMISSION WITHOUT BUILDING NEW POWER LINES

Grid-enhancing technologies allow more power to be carried through the existing transmission system without building new transmission projects. These solutions are a natural complement to grid utilization, because both make better use of the assets we already have.

ADVANCED CONDUCTORS

Replacing the conductors on existing power lines can allow more electricity to be transmitted safely. Conventional lines are made of a steel core wrapped in aluminum strands. Advanced conductors use composite cores wrapped in aluminum. Advanced conductors are efficient: they experience less line loss and therefore can transmit more electricity. They're strong, lightweight, and they don't expand when heated, which means that wires sag less, which helps reduce wildfire risk.

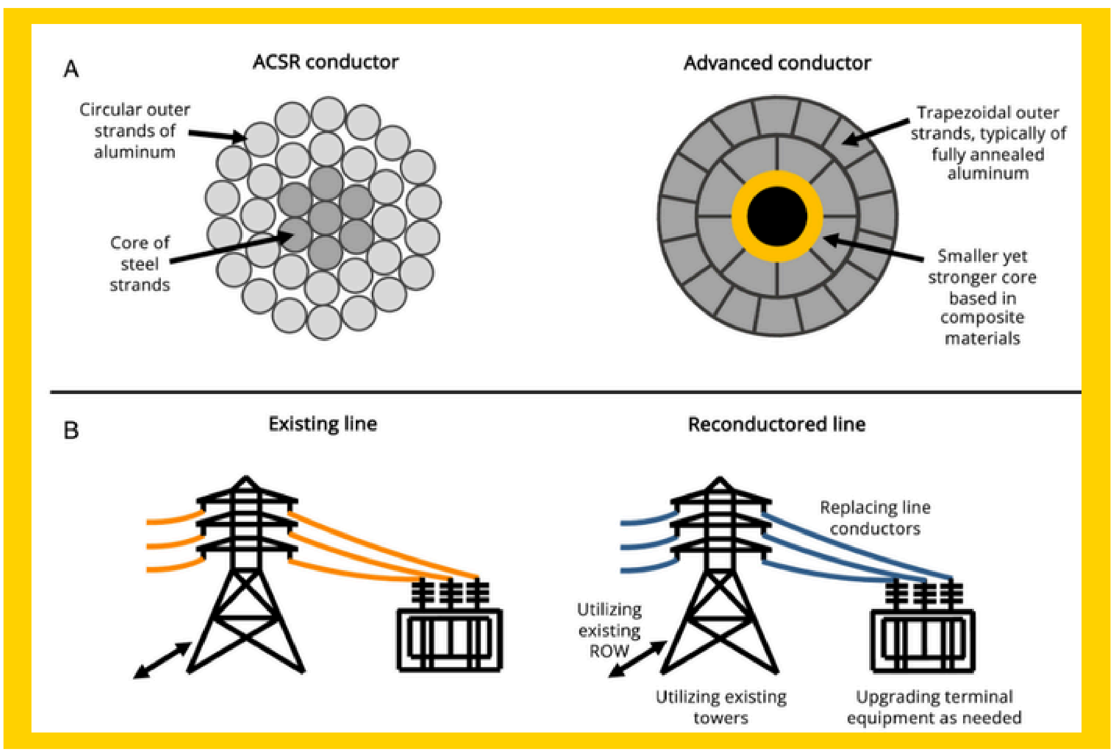


Figure from *Accelerating transmission capacity expansion by using advanced conductors in existing right-of-way*

Montana-Dakota Utilities used advanced conductoring to increase the load on a 230-kilovolt transmission line that connects growing wind farms to the grid. The company used an aluminum-encapsulated carbon fiber core conductor, and saved one year of project time and 40% of the cost by implementing the new technology.

The Idaho National Laboratory published a report of Advanced Conductor Use Case Studies, which profiles different types of technologies and projects deployed at that time (2023). Nearby projects include Black Hills Energy, Montana-Dakota Utilities, Bonneville Power Administration, Avista, Idaho Power. The report includes NorthWestern Energy's use of a 20-mile section of ACSS conductor on the Great Falls-Two Dot line.

To date, most advanced conductoring projects have been for specialized needs, but experts are now advising that their use be expanded to increase capacity more generally. A 2024 study found that large-scale reconductoring can double the transmission capacity within existing rights-of-way. This could save $180 billion in system costs by 2050.

Learn more:
Accelerating transmission capacity expansion by using advanced conductors in existing right-of-way, PNAS, 2024

DYNAMIC LINE RATING

A power line's rating is the maximum amount of electricity it can safely transmit. With a static line rating, that amount can't change, regardless of conditions. Dynamic line ratings can allow more electricity to be transmitted when weather conditions are safe to do so. By using dynamic line ratings, a utility can increase transmission on their existing system.

ADVANCED POWER FLOW CONTROLS

These are electronic devices that control the amount of electricity flowing on individual power lines. When deployed within a grid, power flow controls operate similar to air traffic controllers - they allow the flow of electricity when and where there is capacity, they can shift power flow to underused lines, and they can re-route power around bottlenecks and overloaded areas. Because they can fine-tune grid operations, advanced power flow controls improve reliability and allow more use out of existing infrastructure.

TRANSMISSION TOPOLOGY OPTIMIZATION

This is another solution that helps direct traffic across the grid. Topology optimization can help prevent congestion by redirecting power away from lines that have become overloaded.

Technology	Capability	Demonstration
Dynamic Line Ratings	DLRs adjust the allowable capacity of transmission lines using real-time or forecasted weather conditions.	A 2022 pilot in PA increased line capacity by 25% on average.
Advanced Power Flow Controls	A combination of hardware and software, power flow controls can optimally reroute the flow of electricity using adjustments to line parameters. A common metaphor is that they act as traffic control for electrons flowing on the grid.	An APFC project unlocked 185 MW of capacity in NY in 2024.
Transmission Topology Optimization	Like power flow controls but systemwide, topology optimization uses a combination of hardware and software to reconfigure the flow of electricity on a transmission system, sometimes by "turning off" a transmission line to increase overall MWs.	Alliant reduced congestion by 49%, delivering $24 million in savings over a two-year period.

Examples of grid-enhancing technologies, from *Unlocking the Potential of Grid Enhancing Technologies: Pathways to Widespread Adoption*, Bipartisan Policy Center, 2026

Learn more:
Unlocking the Potential of Grid Enhancing Technologies: Pathways to Widespread Adoption, Bipartisan Policy
Center, 2026
Policies and regulations could go further to prioritize transmission efficiency in the US, NW Energy Coalition
Advanced Grid Solutions, Idaho National Laboratory

NORTHWESTERN ENERGY'S CAPACITY FORECASTS COULD LOOK A LOT DIFFERENT

Every IRP shows similar charts – as power demand increases, so does capacity. Power plants must be built and transmission lines erected. But grid optimization shows that another path is possible. NorthWestern Energy could deploy strategies and technologies to unlock more capacity from its existing system. The solutions described above could help new large load customers come online more quickly, would prevent stranded assets of new power plants built for data centers, and would save money.

But optimizing the grid requires a change in thinking, and most likely, a change in regulations. NorthWestern Energy is not known for its ability to innovate, and it lacks the incentive structure to pursue these solutions. Regulatory action will be needed to guide NorthWestern Energy into a mindset of efficiency rather than ever-increasing asset ownership.

The next section offers specific actions that policymakers can use to usher in a more efficient grid.

A ROADMAP FOR REGULATORS

The report, Grid Growth, Utilization, and Affordability: A Playbook for States, by Deploy Action, lays out a framework for action at the state level.

“To stabilize rates, state leaders must pivot their regional electricity system to reward technology deployment, drive higher utilization of existing assets, and increase speed-to-power without cross-subsidizing large, commercial loads.”

Near-term (2026 - 2030)

- **Scale Virtual Power Plants (VPPs)**

Demand response programs like batteries and smart appliances can lower demand peaks and build capacity more cheaply than building new infrastructure.

- **Increase grid utilization to make better use of existing infrastructure**

Empower state regulators to ask utilities to measure their current grid utilization, and to create incentives for higher levels of utilization, rather than building more assets.

- **Prioritize large load flexibility**

Give data centers the opportunity to connect to the grid faster if they agree to reduce power use during peak events.

- **Modernize rate design and contract structures to protect customers**

Design large load tariffs so data centers pay for the system costs they impose. Use pricing structures to incentivize electricity use away from peak times, for all types of users. Time of use pricing must be designed in ways that protect lower income customers.

- **Pursue permitting reform**

States can take steps to streamline the process of building new electricity infrastructure.

Medium-term (2030 - 2035)

- **Deploy grid-enhancing technologies**

Use available technologies that allow more electricity to flow through the existing transmission and distribution system. Examples include reconductoring, dynamic line rating, and power flow controls. These solutions can be deployed in months, rather than years.

Long-term (2035+)

- **Build the fleet of the future**

Rather than continuing to pay for fuel and maintenance for aging, polluting, and expensive generation, plan for low-carbon, firm generation sources, which cost less and place a much smaller burden on public health and natural resources. Examples include renewables with both short and long-duration storage, and enhanced geothermal. States can start planning now for these long-term projects.

- **Reform utility incentives**

The current regulatory structure will not necessarily produce a more efficient grid, because utilities will continue to pursue incentives to build new infrastructure. But policymakers have the power to change the system to deliver better results. For example, regulations can incentivize an efficient system rather than a larger one. Pollution reductions can be incentivized because that would reduce the costs and health burdens placed on society. Some utilities take the impacts of their pollution seriously, but many do not. Protections for the public are essential to motivate better outcomes and lower costs.

Time Horizon	Solution	Description	Potential Impact	Real-World Examples
Short-term (2026-2030)	**Scale Virtual Power Plants (VPPs)**	Aggregate distributed energy resources - DERS: EVs, batteries, thermostats - to provide capacity, peak shaving, and reliability services at lower cost than new generation or wires	• 80-160 GW of VPPs nationally by 2030 (3x current scale) could address 10 - 20% of peak demand[20] • 40-60% lower net cost than gas peakers or utility-scale storage[21]	• California (DSGS, ~500 MW) • Hawaii (BYOD+) • Colorado (SB 218) • Maryland (HB 1256) • Minnesota (Xcel DER portfolio, ~200MW)
	Increase grid utilization	Empower state regulators to measure grid utilization, and incentivize utilities to achieve higher levels of utilization through energy storage resources, customer-owned capacity, VPPs, and more	• Under the broad umbrella of increasing grid utilization, the US DOE found that proactive utility planning, tariff structures, and vehicle-grid integration could reduce grid infrastructure investments by as much as 30%[22]	• Virginia (HB 434) mandates utilities to align on grid utilization metrics and report annually • Illinois (SB 25) includes provisions to mandate 3GW of energy storage and encourage VPP integration to increase utilization of existing infrastructure • California (DIDF) has a regulatory process designed to identify non-wires alternatives to solve grid capacity needs
	Prioritize large load flexibility	Allow large loads including data centers & industrial facilities to connect faster by covering their own capacity needs and accepting limited curtailment	• 3-5 years faster interconnection[23] • Avoids ~270 MW of new capacity per GW of load, eliminating ~$80 million in incremental system costs per GW of large load[24] • ~76GW of new load (10% of national peak demand) could be integrated with average annual curtailment of ~0.25%[25]	• ERCOT (Connect and Manage) • Arizona data center flexibility pilot (Salt River Project)
	Modernize rate design / contract structures	Default to time-of-use pricing, strong on/off peak differentials, and large-load tariffs to ensure new demand minimizes its coincident peaks and pays for its fair share of system costs	• Customers enrolled in a TOU pilot in California facilitated ~14% average peak reduction and ~8% average bill reduction[26]	• PSEG has implemented 'time of day' pricing to all of its customers (PSEG 2025) • 60+ large-load tariffs have been implemented or are currently being piloted nationally (DELTa database)
Medium-term (2030-2035)	**Deploy Grid-Enhancing Technologies (GETs)**	Increase capacity of existing transmission system via reconductoring, dynamic line rating (DLR), power-flow controls	• Up to 100%+ capacity increase via reconductoring[27] • Dynamic line rating investments payback in 0 - 2 years[28] • In congested regions like PJM, GETs could enable 6.6GW of new projects to interconnect before 2030[29]	• MISO (Reconductoring overloaded lines to ensure only 88% of loaded rating) • CAISO (GETs projects)
	Deliver incremental, firm generation (Uprates & Restarts)	Unlock low-cost, low-carbon, firm capacity from existing hydro and nuclear assets	• 8.5 GWe nuclear reactor uprates have been submitted for NRC-Licensed, Operating nuclear reactors through 2032[30] • Significantly lower LCOE, compared to new generation capacity[31]	• Nuclear uprates (~100MW+ uprates fleet-wide across major nuclear operators) • Nuclear restarts and life extensions (Crane, Diablo Canyon, Palisades)
Long-term (2035+)	**Build the fleet of the future**	Scale low-carbon, firm assets including geothermal, nuclear (Gen III/IV), CCS-equipped gas, long-duration storage	• Including next generation, firm technologies can decrease the total system cost of decarbonization. For example, generation and transmission costs may fall by as much as ~37% with scaled deployment of additional nuclear tech[32]	• Nuclear pilots (Select examples- TVA, Western Interconnect, Dow / Amazon supporting SMRs) • Geothermal pilots (Select examples - Nevada, New Mexico)
	Reform planning, utility incentives	Shift utility earnings from capex deployment to outcomes (affordability, utilization, speed)	• Aligns utility behavior with ratepayer outcomes • Reduces bias toward over-building	• Utility incentive reforms (Colorado, New York, Hawaii)

Learn more: *Grid Growth, Utilization, and Affordability: A Playbook for States*, Deploy Action, 2026

2.BATTERY STORAGE

STORING CHEAP ELECTRICITY FOR USE DURING HIGH-VALUE TIMES

KEY TAKEAWAYS

- Batteries tend to save money because they charge when the grid is experiencing low demand and electricity is relatively inexpensive. Batteries often charge with renewable energy which is also inexpensive. Batteries discharge during the peak times of day when electricity is most expensive. The familiar adage of "buy low, sell high" is an important role of battery energy storage.
- The price of battery energy storage fell 93% between 2010 and 2024, from $2,634 per kWh in 2010 to $197/kWh in 2024.
- Because of the advantages offered by batteries, many utilities in the U.S. have already deployed batteries to manage peaks in electricity demand.
- The Public Service Company of New Mexico is a standout example because they added large amounts of new battery storage and designed interconnection policies that minimize the waiting time for new projects to connect to the grid. Residential electric bills have risen by only 3% over five years, despite the buildout of new, clean energy infrastructure.
- In Wyoming, a new Meta data center will largely be powered by solar and batteries. The large load service agreement between Meta and Black Hills Energy allows the utility to tap into the data center's own, on-site backup generation during systemwide peak events. According to Black Hills Energy, this agreement will defer the construction of an entire power plant.
- In Minnesota, Xcel Energy will be installing small batteries distributed throughout the grid. The program will consist of 200 MW of storage, in the form of batteries that are 1-3 MW in size. The project is intended to relieve constraint on the grid, but in a localized manner.
- NorthWestern Energy currently has no batteries on its system.
- NorthWestern Energy put unnecessary, illogical constraints on batteries in its 2026 IRP. These constraints downplay the advantages, flexibility, and potential of batteries. NorthWestern Energy's analysis does not instill confidence in its understanding of battery energy storage.

INTRODUCTION

Batteries are a time-tested means of storing energy, and most of us interact with batteries every day. When batteries are integrated within the electricity grid, they serve as a predictable and reliable means to manage the ever-changing flow of electricity supply and demand. Energy can be captured when it's cheap and abundant, and discharged during periods of high demand and high value.

Instead of firing up a peaker plant or importing power, a utility can employ batteries instead, which is cheaper, more efficient, and cleaner.

> ***"Batteries fix many of the problems on the grid. It helps us utilize it better. It makes it more reliable. It makes it better at handling and delivering intermittent renewable power. It makes it cleaner."***
> **Pier LaFarge**, founder and CEO of Sparkfund

We're in the steep part of the adoption curve for batteries, and they're proliferating across the world's electricity infrastructure in many different ways. Batteries both large and small are being used to solve various problems – from mitigating peaks, to managing local grid congestion, to balancing out data center loads. This report contains several examples of how batteries are being adopted by U.S. utilities. NorthWestern Energy already recognizes that batteries will bring value to its system, but its analysis in its 2026 IRP likely downplays the flexibility, advantages, and potential of batteries.

THE DATA TELLS THE STORY: THREE DIFFERENT BATTERY SCENARIOS IN THE U.S.

1. NEW MEXICO: EXCELLENT INTERCONNECTION PLANNING BRINGS SOLAR + BATTERIES INTO HARMONY, CHEAPLY.

Currently, The Public Service Company of New Mexico is a compelling example of the advantages of battery storage. The graph below shows electricity generation in late May 2026.

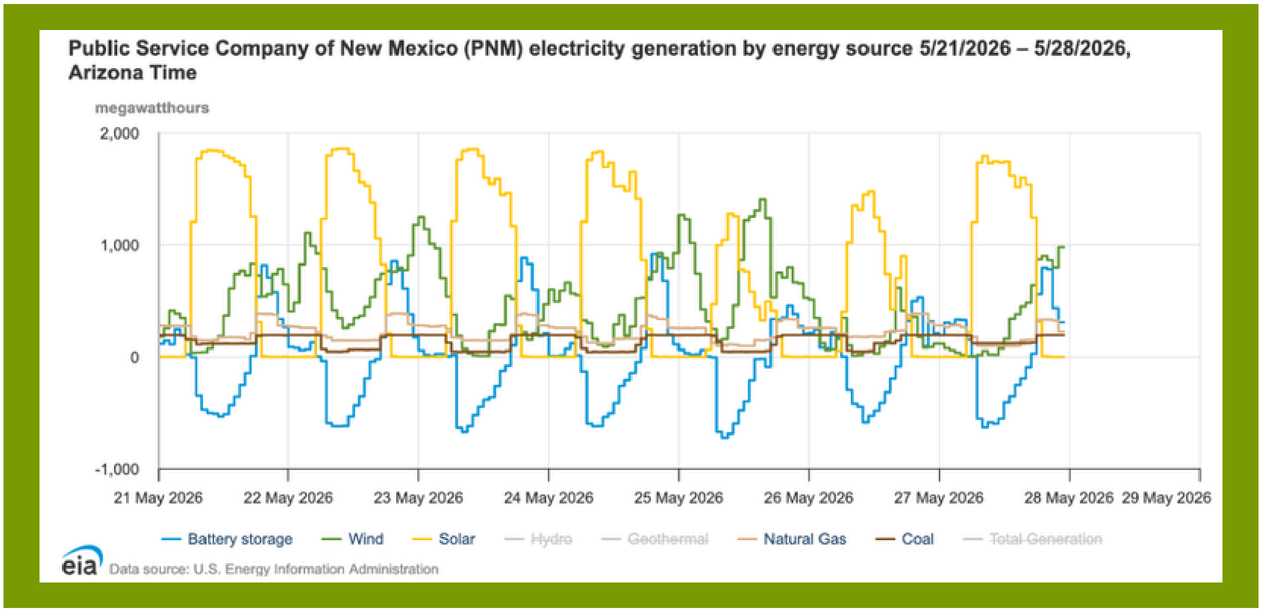


Image from US Energy Information Administration, *https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/PNM*, 2026

During the day, solar production ramps up beyond electricity demand. Without batteries, this energy would be wasted because the timing of solar power production doesn't match the timing of electricity use.

Instead of curtailing solar energy or exporting it at a low price, excess generation is used to charge grid-scale batteries. And better yet, the batteries are charged with zero fuel costs.

Peak electricity demand occurs from 3:00 to 10:00 pm. The early part of that peak is met by solar energy, but the highest demand occurs at 7:00 pm, when there is little to no solar production. Instead of running a peaker plant, this problem is easily solved with batteries. The batteries begin to discharge as solar production wanes, and battery output is controlled to match the evening peak as it develops. In the graph above, the batteries' peak output ends around 10 pm, as demand drops off.

This is a cost efficient grid. The residential price of electricity shown in the graph above averages 12 cents per kWh, plus approximately $12/month for electricity service. Electricity use above 900 kWh per month is billed at a higher rate of 20 cents per kWh.

The Public Service Company of New Mexico also has time-of-use rates for residential, commercial, and large load customers to incentivize users to consume energy outside of peak hours.

Residential electricity bills for the Public Service Company of New Mexico (PNM) have risen just 3.2% over the past 5 years, according to Heatmap's Electricity Price Hub.

New Mexico's electricity prices remain below average, with residential electricity at $0.148 per kWh in June, 2026, compared to the national average of $0.182 per kWh.

For comparison, according to NorthWestern Energy's filings at the PSC, its rates have increased more than 40% over five years.

These enviable results are the result of years of planning, and New Mexico is the only state to earn an “A” grade for its interconnection policies. These policies allow the utility to bring distributed energy resources like solar and batteries into the grid efficiently, reliably, and quickly.

This same report awarded Montana a “D” grade, with recommendations to “significantly update its interconnection procedures to streamline review processes, reduce costs, and improve transparency for interconnection applicants and utilities.”

Learn more: New Mexico has the nation’s best DER interconnection policy

New Mexico has a state mandate to generate 100% carbon-free electricity by 2045. The 1,848 MW coal-fired San Juan Generating Station was retired in 2022, and the Public Service Company of New Mexico owns a small share (200 MW) of the coal-fired Four Corners Steam Plant.

New Mexico’s efficient and economical electricity supply is the result of multiple factors: state legislation to speed the transition to lower cost energy sources, thoughtful planning to evolve its grid from coal-dominated and centralized to a network of clean, connected, distributed resources, and a priority to leverage an inexpensive asset that the state has in abundance: sunshine.

Arizona and California both have a similar rhythm of solar generation and battery storage.

2. TEXAS IN THE WINTER: GAS, SOLAR, AND WIND DOMINATE THE GRID, WHILE BATTERIES TAKE THE EDGE OFF

Texas has installed more grid-scale batteries than any other state, though they account for a smaller proportion of power compared to states like New Mexico or California.

The example below is from February 2026. Wintertime typically brings two daily peaks of electricity use – one in the morning and the other in the evening. On the ERCOT grid in Texas, batteries help offset the morning and evening peaks, as seen in the graph below.

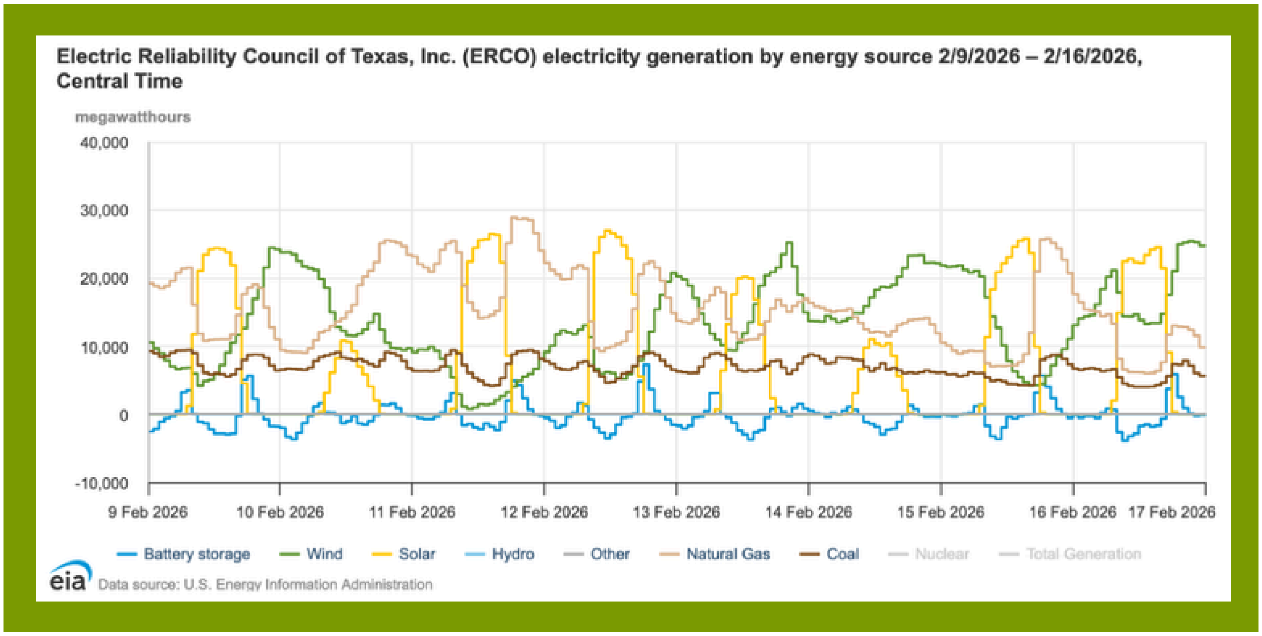


Image from US Energy Information Administration, *https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ERCO,* 2026

Batteries come nowhere close to meeting the entire peak, rather they dampen and lower the peak to make it more manageable by other energy resources. In the example above, the batteries discharged more during peaks when wind energy production is low, such as the evening of Feb. 12. That day, peak demand was at 7:00 pm, and batteries discharged 7,277 MWh to the grid, which met 14% of total demand during that hour. The batteries reduced the need for expensive gas or coal generation or imports during peak hours when electricity is costly.

As in New Mexico, the batteries charge during the day when demand is low and energy is being produced by wind, sun, or both.

3. ROCKY MOUNTAIN POWER: OPPORTUNITY MISSED

Rocky Mountain Power serves parts of Wyoming, Utah, and Idaho. There are few batteries on their system, so it offers a contrast to the examples above.

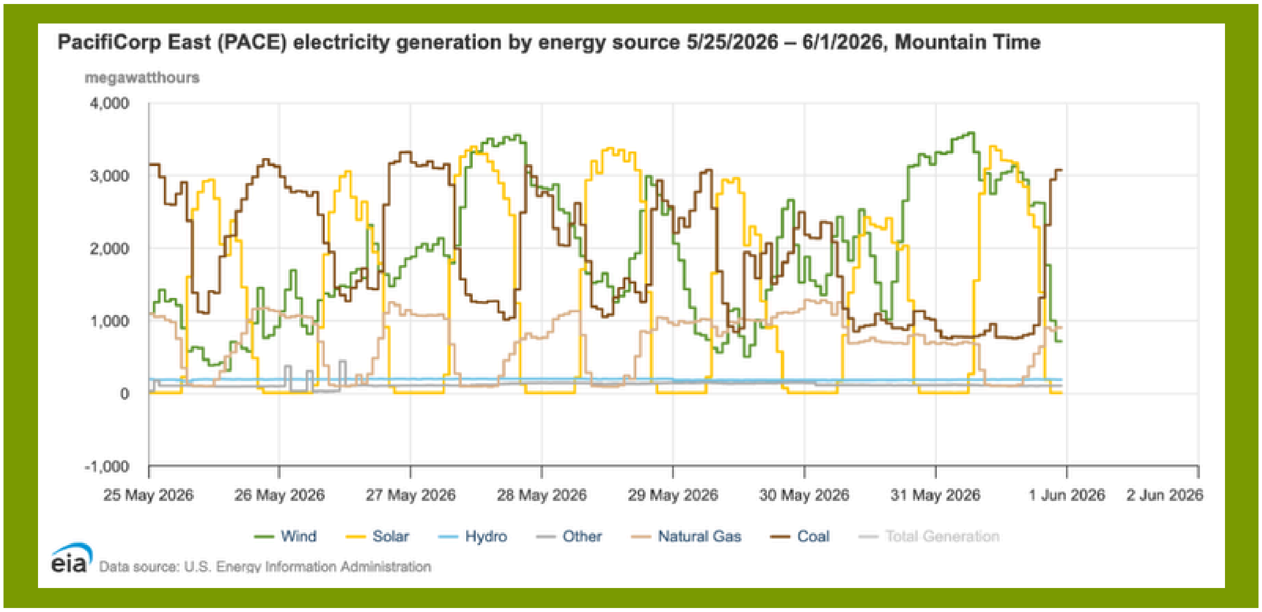


Image from US Energy Information Administration, *https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/PACE,* 2026

This graph shows late May 2026. As with the other examples, solar generation is high during the daytime, but when the sun sets there are no batteries to help serve the evening peak. Instead, the utility meets the peak with coal and gas. Coal generation is cycled up and down daily, with a steep ramp-up to match rising demand as the sun sets.

Coal power plants are designed to operate in a steady-state manner, with slow ramping times and infrequent swings in output. Using a coal plant as a peaking resource causes the plant to operate at lower efficiency, which results in a higher fuel cost and larger pollution burden for each kilowatt hour of electricity produced. Furthermore, coal plants were not designed for rapid and frequent cycling, and using coal power plants in this manner puts additional wear and tear on aging equipment.

Learn more: Coal plants increasingly operate as cyclical, load-following power, leading to inefficiencies, costs

Another disadvantage with Rocky Mountain Power's electricity management is that without batteries, there is no means to store excess generation when both wind and sun are producing at high capacity. Instead, that excess electricity is curtailed or exported and sold at a time of day when electricity has a low market value.

May 31 shows an example of excess generation. Wind and solar were collectively producing more than demand, but the system had no capacity to store that energy for later – and high value – use. This is a lose-lose proposition for ratepayers, as electricity is sold off at a low price, and then more expensive forms of generation are needed only a few hours later.

TWO INNOVATIVE EXAMPLES OF USING BATTERIES - ONE LARGE AND ONE SMALL BUT NUMEROUS

WYOMING: BLACK HILLS ENERGY TAPS INTO A DATA CENTER'S BACKUP ENERGY TO MANAGE PEAKS

The Cowboy Project is a Meta data center under construction near Cheyenne, Wyoming. The data center will be partially powered by 365 MW of solar and 200 MW/1600 MWh of batteries. The batteries will be able to provide maximum power for eight hours, according to the companies.

The solar and batteries will be built by Enbridge, which is an independent power producer. The electricity will then be delivered to the data center by Cheyenne Light, Fuel and Power, which is a subsidiary of Black Hills Corporation. (Black Hills is currently seeking approval to merge with NorthWestern Energy.) Meta will also have its own backup energy supply on site, in case of service disruptions from the utility.

The most interesting part of the project is what happens during periods of high demand. Typically, data centers draw peak power from the utility, which can potentially raise prices for ratepayers and require additional power plants to be built to meet peak demand. But this arrangement is the other way around: during periods of high demand, the utility can tap into some of the data center's own, behind-the-meter backup electricity supply. According to Black Hills, this defers the need to build a new power plant. The agreement is part of Black Hills's Large Power Contract Service Tariff.

This example shows how a thoughtful large load tariff can require that data centers help lower peaks, rather than make them worse.

Learn more: Enbridge and Meta announce massive Wyoming solar and energy storage facility to serve data center needs

MINNESOTA: SMALL, DISTRIBUTED BATTERIES ALLEVIATE LOCAL PEAKS

Minnesota's Public Utilities Commission just gave Xcel Energy approval to install small batteries distributed throughout the grid. The program is called Capacity*Connect, and it will consist of 200 MW of storage, in the form of batteries that are 1-3 MW in size. The project is intended to relieve constraint on the grid, but in a localized manner. There are several advantages of putting the smaller batteries in multiple locations, compared to large battery farms.

- Local batteries can meet local peaks. They can be positioned closer to the parts of the system that need it most.
- For example, batteries can be installed in places that have multiple loads with similar timing, places where there is a bottleneck in transmission or distribution, or near commercial or industrial customers with larger loads.

- The batteries have a small footprint and are easier to site compared to large battery farms.
- The batteries are prepackaged and standardized.
- Landowners who host batteries will get paid by the utility. The utility owns, operates, and maintains the batteries.
- Example locations are big box stores, churches, parking lots, and unused land.
- Placing batteries in underserved communities ensures reliable electric service for all.

A similar program is underway in Virginia, where the Blue Ridge Power Agency is installing five, 5MW batteries to bolster reliability for local electric co-ops and the municipal utility for the city of Salem, VA. The batteries will help these smaller utilities store cheap power and dispatch it during expensive peaks.

Learn more: Minnesota approves Xcel's utility-owned battery program

BATTERY ENERGY STORAGE IS A MATURE TECHNOLOGY THAT IS GROWING RAPIDLY AND STEADILY

- The U.S. has over 50 GW[1] (144 GWh) of energy storage so far; battery storage has been growing rapidly since the technology became available. (Source: Wood Mackenzie Energy Storage Monitor report)
- Utility-scale battery deployments grew by 37% in 2025 compared to 2024.
- The first quarter of 2026 saw a 32% increase in new battery capacity over the same time period last year, with 9.7 GWh of new storage installed January-March 2025.
- At least 42 states already have grid-scale batteries. Montana's first battery project, the 75 MW Glacier Battery System, owned by Berkshire Hathaway Energy, became operational in January 2026. NorthWestern Energy currently has no grid-scale battery systems.
- About half of the U.S. battery storage projects are co-located with solar and half are standalone. Some grid-scale batteries are co-located with wind, though it is not as common as pairing batteries with solar.

[1] 1 gigawatt is 1,000 megawatts

NORTHWESTERN ENERGY PUT UNNECESSARY, ILLOGICAL CONSTRAINTS ON BATTERIES IN THEIR 2026 IRP

NorthWestern Energy's modeling is only as robust as the assumptions they assign to each energy resource. The 2026 IRP contains some assumptions that downplay the advantages, flexibility, and potential of batteries.

- NorthWestern Energy assumed that Lithium-ion batteries can be charged and discharged only once per day, but that is not necessarily true. The example above from ERCOT in Texas shows how the grid operators use batteries for both the morning peak and the evening peak, capturing value from their battery fleet during both of the most expensive times of day. NorthWestern need not place this artificial limitation on batteries.

- NorthWestern's modeling showed that 300 MW of battery energy storage would create a new winter peak load at 5 AM during the charging period of the batteries (Figure 50, page 141). Its solution to this problem was to decrease the amount of battery storage to 250 MW. This finding is confusing, because there is no need to charge batteries at a time or a rate that creates a peak load. In the example used in Figure 50, the charging should start earlier than is shown in the graph, which would position the entire charging period during a time of lower demand than is illustrated in Figure 50. Also, the rate of battery charging can be slowed to avoid creating a new peak. NorthWestern Energy's analysis does not instill confidence in its understanding of battery energy storage.
- When NorthWestern modeled scenarios without placing constraints on the amount of batteries that could be used (section 7.7.1.1), the model heavily favored batteries, which indeed is an improbable solution. But NorthWestern's response to this is to constrain batteries to the artificially low amounts of 250 MW of 4-hour storage and 150 MW of long-duration storage, without giving explanations for why these numbers represent the best outcome.

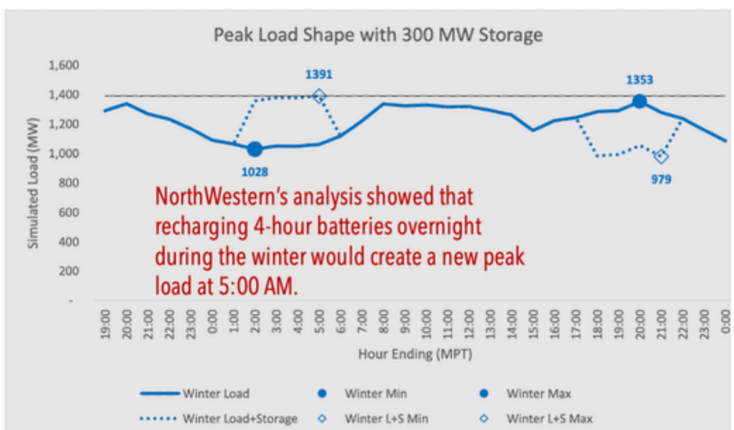


FIGURE 50: NORTHWESTERN'S PROJECTED WINTER RETAIL PEAK LOAD SHAPE WITH 250 MW AND 300 MW, 4-HOUR BESS.

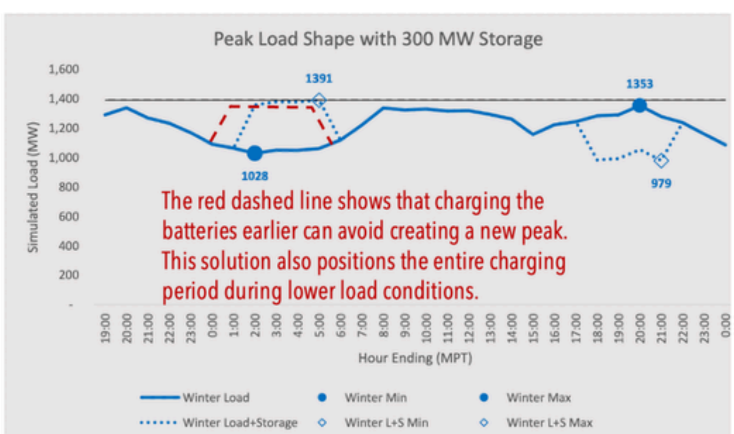


Figure from NorthWestern Energy 2026 IRP
Annotations in red added by Karin Kirk

AS BATTERY PRICES FALL, THEY BECOME AN INCREASINGLY ECONOMICAL WAY TO MEET PEAK DEMAND

- The price of battery energy storage fell 93% between 2010 and 2024, from $2,634 per kWh in 2010 to $197/kWh in 2024.
- Battery prices are expected to continue to fall as the technology improves, modules become increasingly standardized, and the industry grows.
- The current price of battery energy storage, combined with the low price of wind and solar means that renewables with storage are cost-competitive with new combined cycle gas power plants in the U.S.
- The favorable economics of battery energy storage is driving accelerating deployment. As of early 2026, a cumulative total of 175 GWh of battery storage has been installed in the U.S, and the first quarter of 2026 saw record deployment compared to previous years.

Learn more:

Solar and Storage Industry Research Data, Solar Energy Industries Association, 2026
24/7 Renewables: The Economics of Firm Solar and Wind, IRENA, 2026
How cheap is battery storage? Ember, 2025

LITHIUM-ION BATTERY STORAGE IS EFFICIENT

Lithium-ion (Li-ion) batteries lose only a small amount of energy when charging and discharging, and their round-trip efficiency is 77-95%,[2] according to a literature review by consulting firm DNV for the New York State Energy Research and Development Authority. The U.S. Energy Information Administration found that battery storage in the U.S. has a round trip efficiency of around 80%. Ember reported that newer batteries are achieving round trip efficiencies of 90%, while older generation batteries have efficiencies of 80-85%.

For context, the efficiency of coal-burning power plants in the U.S. in 2024 was 32%, and natural gas plants were 44% efficient. The large inefficiencies from thermal generation have become commonplace and accepted, in part because few other options existed in the past. Today, innovations like Li-ion batteries are paving the way for a less wasteful energy system, particularly when batteries are paired with renewables. Batteries can capture inexpensive electricity and store it until it's more valuable, with little loss of energy in the process.

[2] DNV, Energy Storage System Performance Impact Evaluation, 4.

LONG DURATION STORAGE CAN SERVE WINTER PEAKS

The standard battery being installed on the U.S. grid today is a 4-hour, lithium-ion battery. But winter peaks are likely to need more than 4 hours of storage. There are several options for long duration storage.

Longer-duration Li-ion batteries are becoming increasingly economical as battery prices fall. The Tumbleweed Project in California is one of the first, large-scale, long-duration battery projects in the U.S. The 125 MW/500 MWh project consists of Li-ion batteries. As reported by Canary Media, in order to serve an 8-hour load instead of a 4-hour load, the company doubled the number of battery boxes on the site.

Iron-air batteries can deliver power for multiday time periods. Form Energy is building a 300MW/30 GWh battery to serve a Google data center in Minnesota. The battery will be built in West Virginia, and the company says the iron-air batteries can cost-effectively store and discharge energy for up to 100 hours.

- These batteries have a low materials cost because they're made of iron, air, and water. The use of abundant and common ingredients avoids supply chain constraints and geopolitical risks.
- Iron-air batteries are a good match for wind generation which can have longer periods of low production.
- Iron-air batteries have a low round trip efficiency of around 40-50%, but they are cheap to build, so they can be scaled up to offset their lower efficiency.

Liquid electrolyte flow batteries use two tanks of low-cost electrolyte solutions. The duration of storage can be increased by using larger tanks, or more tanks. ViZn Energy is a company in Columbia Falls, MT that builds flow batteries.

Thermal storage uses molten salts to absorb and retain heat. Concentrating solar power plants use thermal storage.

Pumped storage hydropower shifts water between an upper and a lower reservoir. When water flows downhill, it spins turbines and generates electricity. When energy is plentiful and/or cheap, the water is pumped back up to the upper reservoir so it can be available for the next cycle.

The Gordon Butte Pumped Storage Hydro Project is an innovative pumped hydro facility proposed near Martinsdale, Montana.

Compressed air energy storage involves pumping compressed air into an underground cavity such as an abandoned mine, borehole, or natural cavern. The air is released and passed through a turboexpander generator, which generates electricity.

According to Wood Mackenzie's LDES 2025 Outlook, the most common types of long duration energy storage built worldwide in 2025 were advanced compressed air energy storage (45%), thermal storage (33%) and vanadium redox flow batteries (21%). China leads the world with 93% of long duration storage projects so far.

From Minor Player to Major League: Moving Beyond 4-Hour Energy Storage, NREL, 2023

BATTERY CHEMISTRY IS CHANGING, AND GRID-SCALE BATTERIES ARE LESS RELIANT ON CRITICAL MINERALS

In addition to iron-air batteries, sodium-ion batteries are another battery technology made from common minerals. Sodium-ion batteries are a relative newcomer, first deployed to the U.S. grid in 2025. The chemistry of sodium-ion batteries is less reliant on the Chinese supply chain, and sodium-ion batteries are cheaper to operate than lithium-ion batteries because they don't need active cooling systems. According to Peak Energy, a U.S. based company that is building grid scale sodium-ion batteries, they cost less to operate and degrade nearly 30% slower over 20 years.

The drawback is that they are less energy dense, an attribute that is important for cars, but not important for stationary, grid-scale batteries.

Learn more:
Sodium-ion batteries enter energy storage market, Wood Mackenzie, 2025
Peak Energy deal marks progress for sodium-ion batteries in U.S.

REFERENCES AND RESOURCES

Battery Storage Projects in the United States – Cleanview's real-time database and map of battery storage projects in the US, updated monthly.

3.DEMAND RESPONSE

SHIFTING THE TIMING OF PEAK LOAD CAN REDUCE PEAK DEMAND, SAVE MONEY, AND REDUCE POLLUTION

KEY TAKEAWAYS

- NorthWestern Energy currently has no demand response program and no plans to use demand response to lower peak electricity demand. Multiple energy experts, regulators, and members of the public have advised NorthWestern Energy to improve demand response and demand side management.
- NorthWestern Energy hired a consulting firm to assess potential ways to use demand response to lower peaks. The report showed that NorthWestern Energy could lower peak demand by 121 MW in the summer and 45 MW in the winter. For context, the Yellowstone County Generating Station has a capacity of 175 megawatts.
- NorthWestern Energy appears unmoved by these potential savings, and did not include any demand response programs in its 2026 IRP, even when the Public Service Commission asked it to do so.
- Most utilities already use demand response to lower peaks, and several in our region are lowering their peak demand by 8 to 10%.
- Customer-owned, small scale battery storage is another potentially large opportunity that's being used by other utilities in our region.
- Demand response for data centers and other large load customers offers potentially large savings and this strategy is already being rolled out around the U.S.
- NorthWestern Energy is courting multiple data centers, but it has not developed a program for flexible loads from data centers.

NorthWest Power and Conservation Council demonstrates the value of demand response with the following graphic.

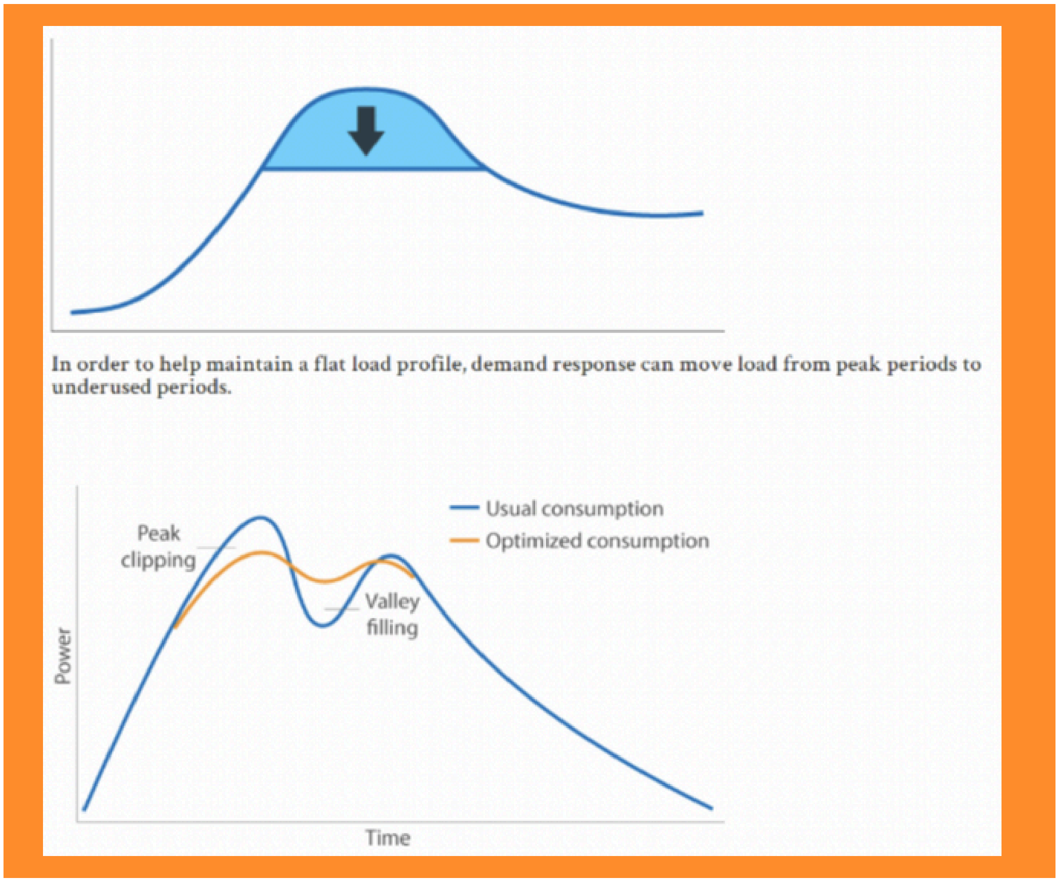


Image from NorthWest Power and Conservation Council, 2026

DEMAND RESPONSE IS EASY, FAST, AND CHEAP

MANY GRID OPERATORS AND UTILITIES ARE REALIZING THAT THE MOST STRAIGHTFORWARD SOLUTION FOR ADDRESSING PEAK DEMAND IS REDUCING IT. ENEL NORTH AMERICA

Demand response is one of the quickest and cheapest ways to lower peak electricity demand. The concept is simple: shift some electricity use to the hours before or after peak demand, which alleviates stress on both power plants and the transmission system, reduces the need to purchase electricity from the market at the most expensive time, and lowers cost. Demand response can be used by large load customers, businesses, and households. It can be required for large load customers and voluntary and incentivized for households and small businesses.

"These programs are designed to save consumers money while simultaneously allowing utilities to avoid spending ratepayer dollars to procure energy on the market, or build new resources and upgrade existing infrastructure."
Understanding Energy in Montana, by **MT DEQ**

The potential for demand response is becoming ever greater as electricity use is becoming increasingly interconnected and automated. For example, smart thermostats, hot water heaters, home batteries, and EV chargers can all be integrated into demand response programs to seamlessly lower peak demand.

It's especially important that data centers reduce their peak energy use, and there are many tools to help them do that. Some energy experts advocate that demand response should be required from data centers as part of their electric service agreement, and that this arrangement should be made public so people can understand how data centers are interacting with the grid.

Lastly, reducing peak demand has add-on benefits of saving money and reducing pollution. During times of peak electricity demand, resources that may normally not be used at full capacity are pressed into service, often with a higher price tag and a larger pollution burden.

A relatable analogy for demand response is Thanksgiving dinner. It's one of the busiest times of the year in many kitchens, but most people intuitively use a system that's a lot like demand response. They prepare foods like casseroles the previous day, they do labor-intensive tasks like baking pies before guests arrive. Only the most essential and time-sensitive tasks are done in the crux moments leading up to dinnertime. And, obviously, cleaning the dishes isn't even tackled until much later in the evening, if not the next day. All of these actions help spread out the workload and kitchen capacity during an unusually busy time, which reduces stress and improves the likelihood of a successful dinner. That's demand response in a nutshell.

NORTHWESTERN ENERGY COULD USE DEMAND RESPONSE TO LOWER ITS PEAK DEMAND BY 3-9%

NorthWestern Energy commissioned a report by the Allied Energy Group to assess potential demand response programs and estimate the amount of capacity that could be saved.

The report states that NorthWestern could achieve 108 MW of demand reduction in the summer and 43.5 MW in the winter through demand response programs by 2034. This would reduce the summer peak load by 9%, and the winter peak by 3%. In the summer, the potential savings are equivalent to 62% of the total capacity of the Yellowstone County Generating Station.

These estimates are in line with or slightly smaller than what neighboring utilities are already achieving, which illustrates that these gains are realistic, and that NorthWestern could in fact aim higher if it wants to match what its peer companies are achieving.

ENERGY EXPERTS, REGULATORS, AND MEMBERS OF THE PUBLIC HAVE ADVISED NORTHWESTERN ENERGY TO DO MORE WITH DEMAND RESPONSE AND DEMAND SIDE MANAGEMENT

NorthWestern Energy does not have any programs to lower peak demand, and its 2026 IRP shows that three different advisory and regulatory groups, as well as members of the public, asked it to pursue demand response. The following excerpts from the 2026 IRP show how these different groups asked NorthWestern Energy to do more.

Following its review of the 2023 IRP, the Public Service Commission asked NorthWestern Energy to include more planning for demand response in the 2026 IRP. "The Commission expects NorthWestern to incorporate the results of the energy efficiency potential study currently being conducted by the Applied Energy Group. Based on this study, the Commission expects NorthWestern to develop a concrete action plan for acquiring the identified demand side management resources. A more comprehensive evaluation of demand side management options is also expected."

NorthWestern Energy's Stakeholder Working Group commented that "demand-side management, energy efficiency, and demand response are among the lowest-cost and fastest-to-deploy resources yet are underutilized in the IRP's core modeling framework."

The Electric Technical Advisory Committee (ETAC) was established by the state legislature to provide input and recommendations to NorthWestern Energy. "ETAC members view demand response as an underutilized resource. They would like to see NorthWestern explore better division by customer type, improved quantification of demand response potential, and exploration of data centers as potential flexible or backup-contributing loads. ETAC members commented on their view that NorthWestern should use third-party demand response aggregators and update demand side modeling to reflect current potential."

"Public commenters emphasized that demand-side management, energy efficiency, and demand response are among the lowest-cost resources available. Commenters expressed concern that the IRP treats these measures primarily as load forecast adjustments rather than as foundational capacity resources."

Beyond the state's borders, the Northwest Power and Conservation Council was authorized by Congress to develop a region-wide power plan to "ensure the Northwest has an adequate, efficient, economical, and reliable power supply." The 2021 Northwest Power Plan recommended that utilities examine two demand response products: residential time-of-use rates and demand voltage regulation (DVR). Its assessment showed potential savings of 520 megawatts of DVR and 200 megawatts of time-of-use available in our region by 2027.

INSTEAD OF INCLUDING DEMAND RESPONSE IN ITS IRP, NORTHWESTERN ENERGY DEFENDED THE REASONS IT WILL NOT FOLLOW COMMISSION EXPECTATIONS.

NorthWestern Energy does not describe any current or future demand response programs in its 2026 IRP. The utility does strive to reduce a small amount of load with energy efficiency programs, but it does not use demand response programs to shift electricity demand outside of peak hours or days.

NorthWestern Energy stands in stark contrast to other utilities. In 2024, 339 different utilities reported energy savings they've realized through demand response programs.

In the final IRP, NorthWestern Energy offered several reasons why it does not plan to increase its ambitions for demand response programs. These claims don't stand up to scrutiny.

NorthWestern Energy Claim 1:
While DR may play a role in portfolio diversification, the 2024 Market Potential Study indicates that total achievable DR reaches only 7–18 MW by 2027 and approximately 45 MW by 2044."

Counterpoint A:
That statement leaves out some important findings from the report. The summer achievable potential was determined to be 121 MW by 2044, which is equivalent to 69% of the total capacity of the Yellowstone County Generating Station. This is a significant savings, especially because NorthWestern's own forecasts show that summer peaks will be higher than winter peaks in the near future.

Counterpoint B:
Other utilities are already achieving much higher savings with demand response than what is stated in the report. For comparison, Montana-Dakota is already achieving 59 MW of demand response from the commercial sector alone.

NorthWestern Energy Claim 2:
"…difficult to scale during Montana's extreme cold winters where safety is important."
"DLC (direct load control) options for existing customers provide limited availability during winter peak conditions."

Counterpoint:
This point hinges on a single, narrow slice of demand response – wintertime residential heating – but that is just one aspect of demand response. A study for PacifiCorp found that grid-connected hot water heaters and small battery energy storage are low-cost options for addressing winter peak demand in cold climates. Furthermore, this comment from NorthWestern ignores summer peaks, which are growing larger over time. NorthWestern's own forecasting shows that it expects summer peak load to exceed winter peak load in the near future. Lastly, demand response applies to much more than residential users. Commercial and industrial customers can shift the timing of their energy-intensive processes without compromising safety.

NorthWestern Energy Claim 3:
"NorthWestern will continue exploring enhancements to pricing-based programs and evaluating opportunities to pair demand response with large flexible loads such as data centers."

Counterpoint:
There are no provisions for demand response in NorthWestern Energy's large load tariff. The only mention of curtailment was for emergency events. Other utilities, like Black Hills Energy, are already making agreements with data centers for demand response and flexible loads. This topic is discussed in Section 1, Grid Utilization.

NorthWestern Energy Claim 4:
"NorthWestern will continue to monitor demand side management opportunities, reassess program design options based on evolving technology and customer participation data, and evaluate additional measures as market conditions change."

Counterpoint:
This statement does not include any goals, commitments, methods, or timelines. It does not appear to be a concrete response to those who have asked NorthWestern Energy to do more. The Public Service Commission stated that it expects NorthWestern to develop a concrete action plan for acquiring demand side management resources, and NorthWestern has made no provision to meet that expectation.

THERE ARE MANY WAYS TO REDUCE PEAK LOAD

Demand response programs are already being used successfully all around the country. There are a variety of programs to suit different electricity customers, different times of year, and different types of peak events. Many of these programs are complimentary with energy efficiency efforts, and they generally save money for the end user and the utility.

Demand response for data centers

Because data centers will be the largest source of load growth in our region, it's important that they operate in a manner that doesn't drive peak demand even higher.

Data centers can reduce their load during system-wide demand events, which offers a substantial benefit to the grid. This is possible because the peak demand for a data center does not necessarily occur at the same time as system-wide peaks, and because data centers can take relatively straightforward steps to reduce their electricity draw from the grid.

During times when the grid is experiencing peak demand (such as a hot summer afternoon), data centers can take the following actions to avoid adding to a peak event:

- Shift their computing workload to facilities in a different region.
- Use their own energy storage system, such as on-site batteries.
- Use their own, on-site electricity generation.
- Pause or slow operations.
- Demand response can be required, and/or it can be incentivized through price structures.

These actions save money and reduce emissions, because regions operating at or near peak demand are both more expensive and more polluting.

Lowering data centers' peak energy consumption can avoid the need to build new power plants, which saves money for both data centers and regular ratepayers. A 2026 study from Duke University found that effective management of the energy demand from data centers can help avoid major capital investments, and can save $40 billion to $150 billion in the U.S. over the next decade.

The section on grid utilization explores the topic of flexible loads for data centers in more detail, and offers some examples where these programs are already underway.

Water heating

The timing of water heating is flexible because water heaters are insulated. A full tank of hot water can stay hot for hours, without additional energy inputs.

- Grid-interactive water heaters can communicate with the utility, allowing the unit to be controlled remotely.
- A study for PacifiCorp found that grid-interactive water heaters are "a large new opportunity for utility demand response, particularly as a means of reducing winter peaks."
- The same study found that the potential for grid-interactive water heaters is higher in the winter than in the summer because water heating often occurs during peak demand. The timing can be shifted outside of peak hours relatively easily and non-intrusively.
- This solution does not necessarily rely on new water heaters. A similar result can be achieved by placing a direct load control switch on existing water heaters.
- Hot water heaters with direct load control were among the cheapest ways to add capacity to the grid in the wintertime, with an estimated levelized cost in Wyoming of $84 per kW in the winter, and $182 per kW in the summer, based on a 2021 study for PacifiCorp.

Small scale battery energy storage

Small batteries installed at homes and businesses can offer a win-win solution that benefits both the customer and the utility.

- Customers purchase qualifying batteries with internet-enabled control of battery charging and discharging.
- The customer uses the battery as they like, and the utility also has the ability to draw from the battery as needed.
- In some cases, customers receive payment for the energy drawn from their battery.

Examples from our region

- Wattsmart battery program, Rocky Mountain Power: Wyoming, Idaho, and Utah
    - Homes and businesses can install small batteries for utility grid management, with capacity ranging from 5 to 30 kW.
    - Customers choose from a list of qualifying batteries and receive a rebate to offset part of the purchase price.
    - Customers are required to commit to participate in the programs for a minimum number of years to receive an enrollment incentive.
    - After the initial commitment term is complete, customers can earn additional money for the electricity used by the utility, on a per kWh basis.
    - Customers with existing, eligible batteries can participate and receive an annual credit on their electricity bill.
    - Customers use the battery as they like for managing their own energy use.
    - The utility can also use the batteries to discharge power to the grid when needed. Batteries can be discharged for traditional demand response, frequency reserve, contingency reserve, regulation reserves, regional grid management, backup power, and other ancillary benefits in addition to reducing peak load on the electric system.
- The 2021 study for PacifiCorp found that small-scale batteries installed at homes and businesses are a large, emerging demand response opportunity, and they are particularly useful to lower wintertime peaks.
    - For winter peaks, PacifiCorp found that battery energy storage is by far the largest opportunity of all the solutions they evaluated, representing 44% of the total demand response potential in their study.

Demand response for commercial and industrial customers

During peak events, businesses can shift the timing of many of their energy-intensive processes. Participating businesses earn payments for reducing their electricity use during periods of high demand.

- A program from Rocky Mountain Power lists examples of actions businesses can take:
  - Reduce non-essential lighting
  - Modify manufacturing processes
  - Adjust HVAC equipment
  - Dial back pumps
  - Change settings in industrial freezers
  - Utilize back-up generators
- This program is managed through Enel, a third-party demand management service.

Incentivized pricing

Pricing structures give financial incentive to reduce electricity use during peak times. Because electricity costs more during peak times, these programs are economical for the utility as well as the customer.

It's important to note that dynamic pricing can be harmful to low-income residential customers who may not be able to shift the timing of their electricity use or bear the burden of peak pricing. Incentivized pricing programs must be structured in a way that is not economically burdensome to low-income customers. Some examples are opt-in programs, programs with smart appliances, or programs that target larger customers.

The Energy Information Administration defines five types of dynamic pricing programs.

- Time of use pricing – electricity prices vary during the day, according to a predefined schedule based on the season and day of the week. Peak prices are more expensive than the baseline rate, and off-peak rates are cheaper than the baseline rate.
- Real-time pricing reflects actual market conditions, with prices changing hourly or even more frequently.
- Variable peak pricing allows customers to purchase their electricity at prices that are set the previous day.
- Critical peak pricing is used during very high peaks, and the price can be 3-10 times higher than the baseline price. These events are infrequent and short-duration, lasting for a few hours.
- Critical peak rebate gives money back to the customer for reducing consumption during certain hours on peak days. The rebate is several times higher than the standard price, per kilowatt-hour.

Pricing structures can be "opt-in," where customers can choose to participate; opt-out, where customers are automatically enrolled; or mandatory, where the program applies to all users in a specific rate class.

Other tools for reducing peak demand

Connected thermostat
Internet-enabled control of thermostat set points

Smart appliances
Internet-enabled timing of energy-intensive appliances like clothes dryers and dishwashers to avoid peak hours

Automated EV charging
Automated, level 2 EV chargers that postpone or curtail charging during peak hours

Change the timing of irrigation pumps
Delay irrigation during summer afternoon or early evening peak electricity demand

Behavioral demand response
During peak events, customers get an alert from the utility, typically by text message. Customers can voluntarily reduce their electricity use. In some cases, customers receive payment for electricity they reduce. (For example, Sonoma Clean Power pays $2 per kWh). This simple system has proven effective in extreme events when a rolling blackout was imminent. Most of the use cases have been in the summer.

Allow customers to monitor their electricity usage in real time
If customers can see their energy demand in real time, they can make informed decisions about how to shift their usage patterns to avoid peak hours.

Use third-party services that specialize in demand management
There are companies that specialize in managing peak demand for utilities. These companies can design solutions to fit the needs of a particular region and implement them with customized software and apps.

CASE STUDIES FROM OTHER UTILITIES IN COLD CLIMATES

Montana-Dakota

Montana-Dakota has made large gains with demand response programs, especially for a relatively small utility. Their current demand response savings of 59 MW are equivalent to 10% of their average peak load of 597 MW.

- Commercial demand response resources program (described in IRP volume 1)
  - Focused on customers with loads of 150 kW or higher
  - As of 2023, Montana-Dakota had 33 customers enrolled in this program, providing 23.4 MW of demand response
  - Target enrollment for this demand response program is 40 MW by 2027.

- Interruptible large power demand response
  - Customers larger than 500 kW
  - Interruption up to 100 hours per year
  - Remotely operated by the utility on a separately metered circuit
  - As of 2023, Montana-Dakota has 12.8 MW enrolled in this program, with a goal of 20 MW by the summer of 2027.
- Combined, these programs were providing 36.2 MW of demand response at year end 2023, with an overall goal of providing up to 60 MW of demand response by 2027.

Their 2024 IRP volume 2 further describes their demand response goals.

- Peak demand savings:
  - Current demand response programs of 59.0 MW for 2024, rising slightly to 60.0 MW by 2025 - 2042 for the commercial sales sector.
- Demand side management savings:
  - 0.37 percent of annual sales for 2024 through 2042, achieved by growing from 0.18% of total sales in 2023, to 0.43% of total sales by 2030 through 2042, for an overall savings of 0.37% for the 20-year forecast horizon.

Flathead Electric

Flathead Electric uses a demand charge, and electricity costs more during peak hours. They also offer a rebate of $140 for a smart thermostat, and $18 for a line voltage thermostat.

The utility has videos and other resources to help educate customers about ways to save money by avoiding peak hours.

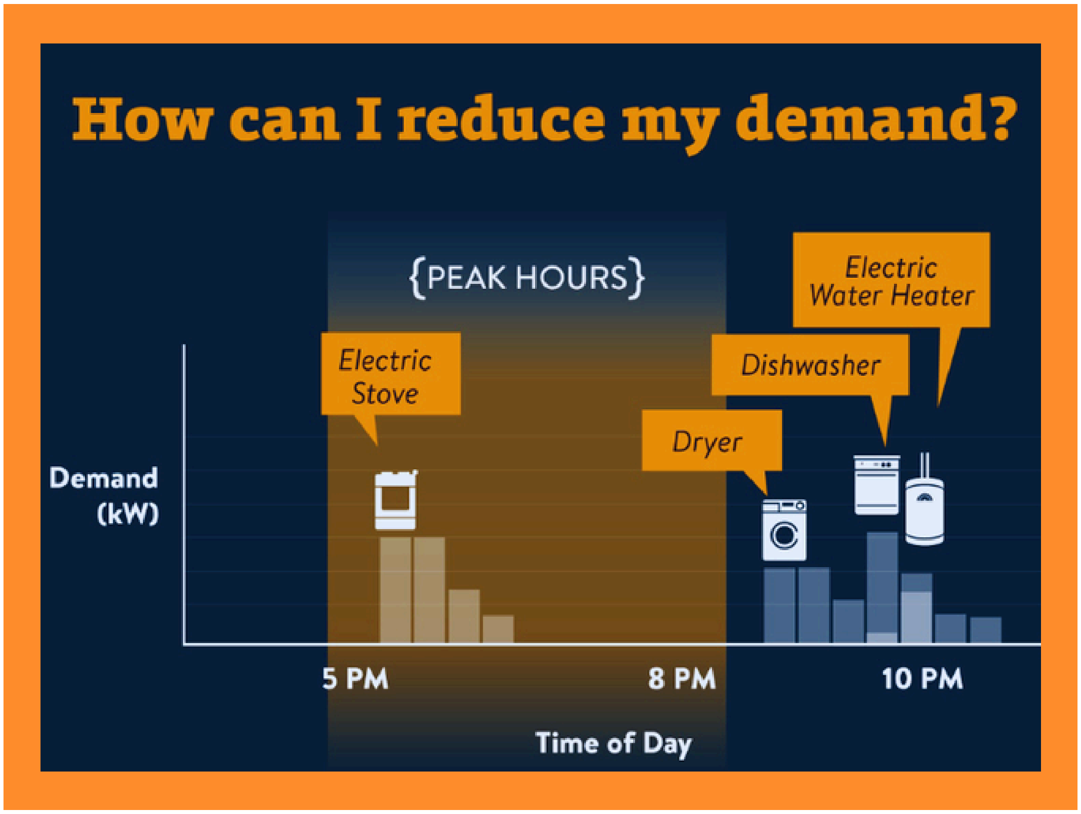


Image from the Flathead Electric website

Idaho Power

In 2024, Idaho Power reported 323 MW of demand response, which is primarily focused on reducing summer peaks. This is equivalent to 8.5% of their total peak load.

The largest component of their demand response program is irrigation pumping, which accounts for 259 MW. A consultant report found that Idaho Power can achieve 145 MW of additional demand response.

Colorado – Xcel Energy

State law mandates demand response targets in Colorado, and Xcel Energy in Colorado is one of the leading utilities in the nation for demand response savings. It achieved 581 MW of demand capacity savings in 2025, and 975 MWh of avoided generation.

A 581 MW reduction of peak demand represents 8% of the utility’s summer peak demand of 7,374 MW.

The 2025 summer demand response savings was 581 MW. The target was 628 MW.
The 2025 winter demand response savings was 287 MW. The target was 287 MW.

The programs with the largest amount of demand response were:
- Residential demand response – 289 MW
- Interruptible Service Option Credit for commercial and industrial customers – 187 MW
- Incentivized pricing programs – 74 MW (total of four different pricing programs)

For more details, see the Colorado Demand-Side Management Annual Report, 2025, pages 97-100.

A demand response study by the Brattle Group found that by 2030, 1,000 MW of demand response is achievable in summer, and 537 MW in winter. Those benchmarks would save 16% of summer peak load and 7% of winter peak. Note that these findings are roughly double what NorthWestern Energy says is achievable.

The largest areas of potential savings are
- Time of use rates for all customer classes
- Time of use rates for EV charging
- A targeted peak time rebate to provide event-based behavioral demand response
- Small scale battery storage

The figure below is from the Brattle Group report and it illustrates each program and potential savings.

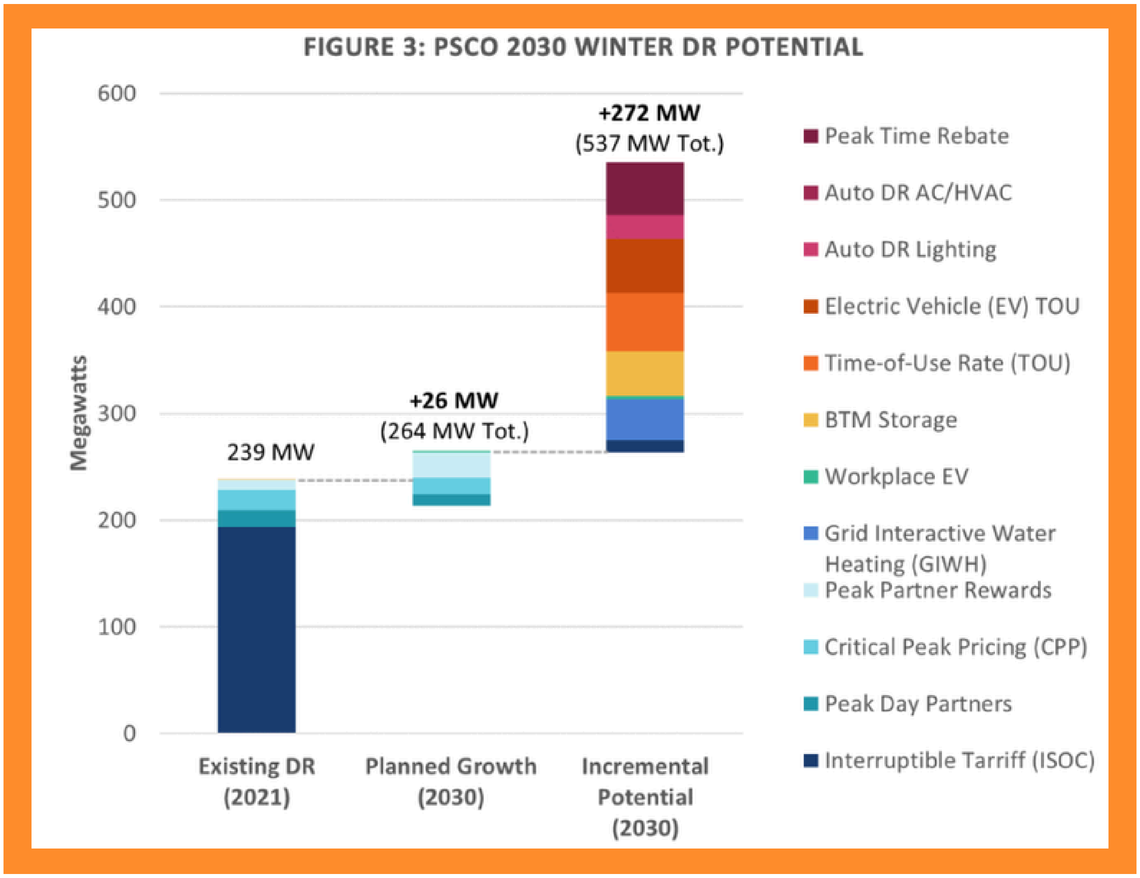
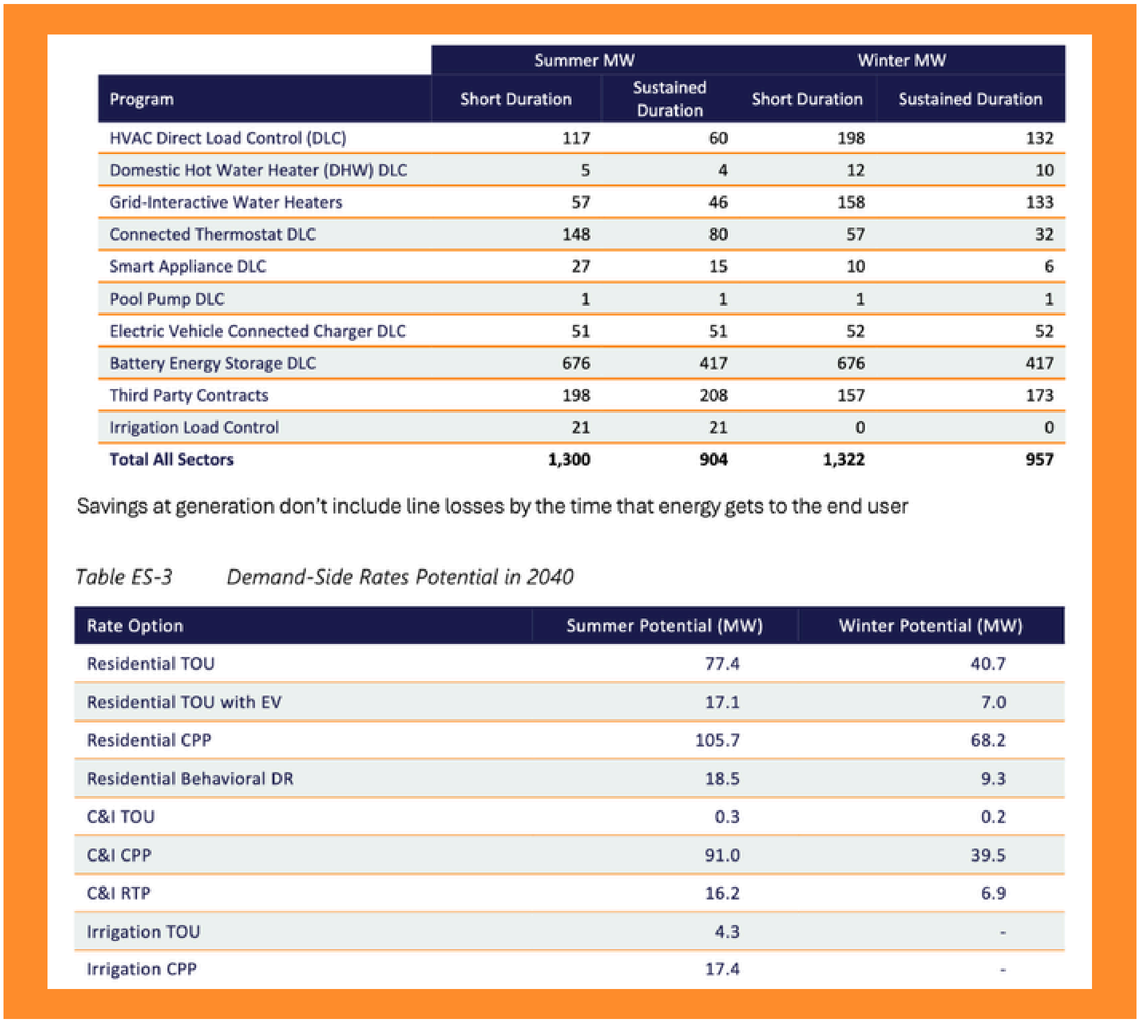


Image from Brattle Group, 2026

PacifiCorp

The PacifiCorp Conservation Potential Assessment for 2021-2040 estimated up to 1,322 MW of short duration winter demand response, and 957 MW of sustained duration (longer than 2 hours) demand response. The report found slightly lower savings in the summer, with 1,300 MW for short duration and 904 MW for sustained duration.

The largest areas of savings for sustained duration in the wintertime are battery energy storage, third party programs, grid-interactive water heaters, and direct load control of HVAC equipment.



Program	Summer MW		Winter MW	
	Short Duration	Sustained Duration	Short Duration	Sustained Duration
HVAC Direct Load Control (DLC)	117	60	198	132
Domestic Hot Water Heater (DHW) DLC	5	4	12	10
Grid-Interactive Water Heaters	57	46	158	133
Connected Thermostat DLC	148	80	57	32
Smart Appliance DLC	27	15	10	6
Pool Pump DLC	1	1	1	1
Electric Vehicle Connected Charger DLC	51	51	52	52
Battery Energy Storage DLC	676	417	676	417
Third Party Contracts	198	208	157	173
Irrigation Load Control	21	21	0	0
Total All Sectors	**1,300**	**904**	**1,322**	**957**

Savings at generation don't include line losses by the time that energy gets to the end user

Table ES-3 Demand-Side Rates Potential in 2040

Rate Option	Summer Potential (MW)	Winter Potential (MW)
Residential TOU	77.4	40.7
Residential TOU with EV	17.1	7.0
Residential CPP	105.7	68.2
Residential Behavioral DR	18.5	9.3
C&I TOU	0.3	0.2
C&I CPP	91.0	39.5
C&I RTP	16.2	6.9
Irrigation TOU	4.3	-
Irrigation CPP	17.4	-

Image from Pacificorp, PacifiCorp Conservation Potential Assessment for 2021-2040, 2026

Oregon – Pacific Power

The 2025 IRP Update preferred portfolio includes:

- 324 megawatts of new demand response capacity by the end of 2030
- 657 megawatts by the end of 2040
- 1,031 megawatts by the end of 2045.

Pacific Power is using a demand response program for commercial and industrial customers who reduce energy usage during periods of high demand.

- Customers can earn incentive payments, ranging from $30,000 to $85,000 per megawatt annually
- The program is run by a third-party company, Enel.

Pacific Power also has a demand response program for residential customers.

- The program uses water heaters and HVAC systems with air conditioning or heat pumps
- Financial incentives of $25 to $50 for enrollment, plus $25 per year of participation
- Available to renters as well as homeowners

Northwest Power and Conservation Council

The 2021 Northwest Power Plan, found large potential savings available in our region.

- Managing demand with a time-of-use price incentive can save 200 megawatts of capacity by 2027.
- Demand voltage regulation lowers the voltage of distribution feeder lines. This can save 520 megawatts of capacity by 2027.

Bonneville Power Administration

BPA's 2024 Demand Response Potential Assessment found large gains can be made with demand response, with potential avoided demand larger than NWE's 814 MW stake in the Colstrip plant.

- Winter technical achievable potential is about 900 to 1,000 MW within 5 years.
- Summer technical achievable potential is about 1,000 to 1,200 MW within 5 years.
- Most potential comes from the residential sector.

A 1,000 MW reduction of peak demand represents 9% of BPA's peak load of around 11,000 MW.

KEY REFERENCES AND REPORTS

Demand Response - A basic explainer by the Northwest Power and Conservation Council

Demand Response in the Northwest: Part 1 - NW Energy Coalition

Understanding Energy in Montana - 2023, Montana DEQ, 2023

2026 Montana Integrated Resource Plan, NorthWestern Energy, 2026

Demand Response Potential Assessment, prepared for the Bonneville Power Administration, 2024

Assessment of Barriers to Demand Response in the Northwest's Public Power Sector, prepared for the Bonneville Power Administration, 2018

Data Center Flexibility and Generation Capacity Over the Next Decade, Duke University's Nicholas Institute for Energy, Environment & Sustainability

Colorado Demand-Side Management Annual Report, 2025

Xcel Energy Colorado Demand Response Study: Opportunities in 2030, 2022

Xcel Energy summary table of demand management programs for businesses

The use of price-based demand response as a resource in electricity system planning, Lawrence Berkeley National Laboratory, (A detailed overview comparing studies from multiple utilities, including the studies used here), 2023

PacifiCorp Conservation Potential Assessment for 2021-2040, Feb. 2021

Operationalizing and Quantifying the Demand Stack The Brattle Group, 2026

4.INTERREGIONAL TRANSMISSION

CONNECTING AREAS WITH EXCESS SUPPLY TO AREAS OF HIGH DEMAND

KEY TAKEAWAYS

- Transmitting electricity between regions is an efficient way to solve peak demand, because peaks in electricity use typically don't happen at the same time in different regions, and excess generation also occurs at different times in different places.
- Long-distance transmission lines that connect neighboring regions can carry electricity from locations with spare capacity to the places that need it most, making the grid more cost-efficient for everyone.
- The North Plains Connector is a 3,000 MW transmission line that will connect the west-coast bound Colstrip transmission line at Colstrip to two locations in North Dakota. Multiple studies have found that the North Plains connector will bring reliable electricity to its co-owners and it can be counted on as a steadfast capacity resource.
- Because it connects three different sections of the U.S. grid, the North Plains Connector will provide energy and capacity during both summer and winter capacity critical hours.
- NorthWestern doesn't account for the added capacity it will get from the North Plains Connector in its modeling or forecasts. Instead, NorthWestern intends to fill its capacity needs by building more power plants, which raises costs for ratepayers.
- In contrast, nearby utilities are considering the North Plains Connector as a capacity resource. Avista is evaluating a 300 MW share of the connector, and Avista's 2025 IRP shows the North Plains Connector as a capacity resource in its planning.
- Portland General Electric has committed to a 600 MW share of the North Plains Connector. Portland General Electric's resource forecasts reflect the full 600 MW of capacity from the North Plains Connector.
- Utilities and system planners should consider interregional transmission to be a capacity resource so that ratepayers get the full benefit of these projects. A proper accounting of the benefits of transmission is needed to prevent overbuilding of new generation resources.

TRANSMISSION HELPS RESOLVE PEAKS BECAUSE DIFFERENT PLACES HAVE PEAKS AT DIFFERENT TIMES

Transmitting electricity between regions is an efficient way to solve peak demand. Peaks in electricity use typically don't happen at the same time across different regions, and excess generation also occurs at different times in different places. Long-distance transmission lines that connect neighboring regions can solve both of these problems at once, carrying spare electricity to the places that need it most, and making the grid more cost-efficient for everyone.

Research backs up this simple premise. A 2026 study looked at what would have happened to electricity prices in 2022 and 2023 if there were better connections between regions. The authors found that costs would have been reduced by $5.8 to $7.1 billion in 2022 and $3.4 to $5.0 billion in 2023. Most electricity generators in Montana would have experienced gains in revenue, according to the study.

NorthWestern Energy knows the value of long-distance transmission, and it described the benefits in its IRP. Interregional transmission provides "new and potentially low-cost energy purchase options in times of energy shortages," when electricity is most expensive. NorthWestern also explained that long-distance transmission can optimize regional electricity markets "by increasing access to more diversified generation resources and loads."

In other words, interregional transmission can help meet peaks in demand for a low cost, and can tap into power generation beyond a utility's own fleet in an economical way.

Two new transmission projects are on the horizon for our region. NorthWestern has signed a memorandum of understanding for a 300 MW share of the North Plains Connector line, which will run from Colstrip to North Dakota, and they have written a letter of intent to participate in a Path 18 transmission line connecting Idaho to Montana. These are smart decisions. But there's one important element missing, which is that NorthWestern doesn't account for the added capacity it will get from transmission in its modeling or forecasts. Instead, NorthWestern intends to fill its capacity needs by building more power plants, which raises costs for ratepayers.

System planners that do not already include the contribution of transmission-enabled imports in their resource adequacy assessments should do so.
Resource Adequacy Value of Interregional Transmission, **Grid Strategies**

THE NORTH PLAINS CONNECTOR WILL LINK MULTIPLE REGIONS AND MARKETS

The North Plains Connector is a 3,000 MW transmission line that will connect Colstrip to two locations in North Dakota. It will connect the grid regions of Western Electricity Coordinating Council (WECC), Midcontinent Independent System Operator (MISO), and the Southwest Power Pool (SPP).

Multiple studies have found the same thing: the North Plains connector will bring reliable electricity to its co-owners and it can be counted on as a steadfast capacity resource.

One of the specific benefits of the North Plains connector is that the regions it connects have different seasonal peaks. The electricity markets at the eastern end of the line have peak demand in the summer, while NorthWestern Energy is primarily constrained by winter demand. Thus, the transmission line can contribute to meeting peak demand in both regions in a complementary way.

A 2024 study by Energy GPS for Portland General Electric looked at the effects of building new transmission to the east, connecting with the Southwest Power Pool or Midcontinent Independent System Operator, as the North Plains Connector does. The study found that Portland General Electric would gain access to energy and capacity during critical peak hours in both the summer and the winter.

A 2024 analysis of the North Plains Connector by Astrapé Consulting found that the 3,000 MW transmission line would improve resource adequacy in every area served by the line. In fact, the study led to a counterintuitive finding that "the effective load carrying capability (ELCC) of the transmission line, if added up individually across the three aggregated regions, is greater than 3,000 MW." This is because of the different seasonal benefits in different regions. The transmission line benefits utilities to our east during their summer peak season and it benefits NorthWestern Energy during winter peak season. It's truly a win-win solution that requires no additional generation. The value comes solely from allowing different places to become interconnected.

NORTHWESTERN ENERGY DOESN'T ACCOUNT FOR THE ADDED CAPACITY OF TRANSMISSION

NorthWestern Energy's 2026 IRP modeled the effects of a 300 MW share in the North Plains Connector on energy production, exports, and imports, but its results showed only a minor reduction in energy production (Figure 123 of the IRP shows a 4% reduction in energy production, or 7 million MWh). NorthWestern Energy does not model the North Plains Connector as a capacity asset. Instead, NorthWestern intends to build more power plants (and/or batteries) to meet its needs. Building more generation while also buying a 300 MW share in the North Plains Connector may lead to an overbuilt system, with those costs borne by ratepayers.

Presently, Western Resource Adequacy Program (WRAP) rules do not allow transmission to be considered as part of resource adequacy. But that is expected to change. WRAP is currently in the process of developing a methodology for determining the value of transmission in resource adequacy, and this updated method will likely be available by the time the North Plains Connector becomes operational. NorthWestern Energy will be able to use transmission as a means to meet resource adequacy and/or planning reserve margin, and it can start planning now so that it can determine the most accurate and efficient forecasts for its future resource needs.

But nearby utilities are considering the North Plains Connector as a capacity resource. Avista is evaluating a 300 MW share of the connector, and Avista's 2025 IRP shows the North Plains Connector as a capacity resource in its planning. As seen in the graph below, the intertie is expected to be available beginning in 2032 and is plotted as a 300 MW resource. The IRP states that the North Plains Connector could replace capacity resources identified in its 2025 portfolio scenario analysis.

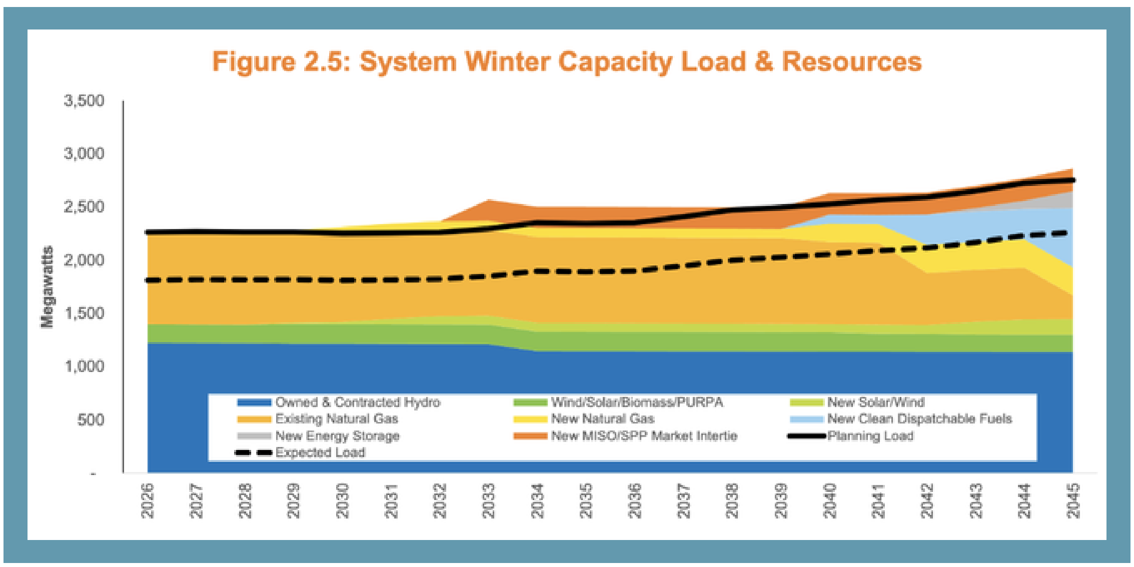


Image from Avista Electric IRP, *file:///C:/Users/keili/Downloads/2025%20Avista%20Electric%20IRP.pdf*, 2025

Portland General Electric has committed to a 600 MW share of the North Plains Connector. Similar to Avista, Portland General Electric's resource forecasts reflect the full 600 MW of capacity from the North Plains Connector. The company is basing its decision on a market study it commissioned (discussed above) that showed that transmission to SPP and MISO will provide energy and capacity during both summer and winter capacity critical hours.

PacifiCorp assigns cost, available year, and capacity increase to various transmission upgrade options. Then its model can select transmission as well as new generation. PacifiCorp's method was used as an example of successful planning in a report by Interwest Energy Alliance. The report describes methods and recommendations to help utilities do a better job in evaluating transmission as part of their IRP process.

TOOLS CAN HELP UTILITIES DETERMINE THE VALUE OF TRANSMISSION

A report by Grid Strategies aims to help utilities and grid operators use interregional transmission to meet their resource adequacy needs. The report authors point out that interregional transmission assets tend to be available nearly 100% of the time, bringing both reliability and cost effectiveness to ratepayers. But the industry doesn't yet have a consistent method for how to account for the capacity value of these long-distance lines.

The report offers several strategies to calculate the capacity value, like the effective load carrying capability (ELCC) method, which is already being used for transmission projects around the country.

Similar to PacifiCorp's method, the Grid Strategies report suggests that utilities can assign a value to transmission capacity and use it as a capacity resource to meet resource adequacy.

Several specific ways to calculate the resource adequacy value are included in the report, for those seeking more details. But the key takeaway is that utilities and system planners should consider interregional transmission to be a capacity resource so that ratepayers get the full benefit of these projects. A proper accounting of the benefits of transmission is needed to encourage investment in transmission and prevent overbuilding of new generation resources.

RESOURCES AND REFERENCES

More interregional transmission could save consumers billions, Utility Dive, 2026

North Plains Connector (NPC) Evaluation, Astrapé Consulting, 2025

Resource Adequacy Value of Interregional Transmission, Grid Strategies, 2025

Evaluating Transmission Opportunities in Integrated Resource Plans, Interwest Energy Alliance, 2025

5.ELECTRICITY MARKETS

ROBUST, ORGANIZED TRADING BETWEEN UTILITIES MAKES THE SYSTEM CHEAPER AND MORE RELIABLE

KEY TAKEAWAYS

- Buying and selling of electricity between utilities brings substantial benefits of reliability, a "right-sized" generation fleet, less curtailment of renewable energy, and lower costs.
- Regional electricity markets help coordinate trade between various utilities in our region.
- NorthWestern Energy is part of the Western Energy Imbalance Market, which organizes trading in real time or near real time. Participating in the Western Energy Imbalance Market has provided NorthWestern with $223.8 million in benefits since it joined in June 2021.
- For longer planning horizons, day-ahead markets help utilities plan for weather, expected demand, and the output of their own fleet.
- NorthWestern is considering joining one of two day-ahead markets, the Extended Day-Ahead Market (EDAM), or Markets +. Either market would bring benefits to NorthWestern Energy and its ratepayers, but EDAM appears to hold more advantages.
- An interconnected Western market can save nearly $1.2 billion each year. EDAM taps into a large fleet of low-cost renewable energy generation, as well as an expansive network of traditional generation sources. The larger the market, the greater the benefits to ratepayers.
- Multiple studies have found that EDAM offers much larger potential for savings, compared to Markets+.
- NorthWestern Energy should not only conduct a careful analysis of both options, but should also release the results to the public and incorporate the analysis into its IRP.

NORTHWESTERN ENERGY ALREADY PARTICIPATES IN ONE TYPE OF ELECTRICITY MARKET, AND IT SAVES MONEY

Utilities don't operate in isolation. If they did, their service would be expensive, overbuilt, and less reliable. Regional electricity markets help coordinate trade between various utilities in our region, which brings substantial benefits of reliability, a "right-sized" generation fleet, less curtailment of renewable energy, and lower costs.

There are different markets for different time scales. Trading in real time or near real time is coordinated through the Western Energy Imbalance Market (WEIM). For longer planning horizons, day-ahead markets help utilities plan for weather, expected demand, and the output of their own fleet.

NorthWestern Energy joined the Western Energy Imbalance Market in June 2021. Participating in the market has saved NorthWestern $223.8 million since then, with $23 million in savings in the fourth quarter of 2025 alone.

Black Hills Energy just recently joined the Western Energy Imbalance Market in May 2026, which expands the market to 12 states and 23 balancing authorities. This development is noteworthy in light of the potential merger between Black Hills and NorthWestern Energy.

TWO OPTIONS FOR DAY-AHEAD MARKETS

NorthWestern is considering joining one of two day-ahead markets, the Extended Day-Ahead Market (EDAM), or Markets +. EDAM taps into utilities and generators in the Western U.S., including California. Markets + is part of the Southwest Power Pool, which runs down the nation's midsection, from North Dakota to Oklahoma.

While either market would bring benefits to NorthWestern Energy and its ratepayers, EDAM appears to hold more advantages.

In addition to day-ahead trading, Markets + also has real-time electricity trading. If NorthWestern joins Markets +, it would have to exit the Western Energy Imbalance Market, which is bringing proven savings for ratepayers. If both NorthWestern and Black Hills opted to join Markets +, they would both have to exit the Western Energy Imbalance Market, even though Black Hills just joined the Western market.

The Bonneville Power Administration (BPA) is currently planning to join Markets +, even though its own modeling showed that joining EDAM would bring a larger financial benefit than Markets +. In its proposed decision, BPA cites that the reasons it prefers Markets + are related to "governance and stakeholder process, resource adequacy and resource sufficiency, price formation and market power mitigation, transmission and congestion rent, and greenhouse gas accounting."

The Brattle Group evaluated the effects of BPA joining Markets + instead of EDAM. Its analysis showed that BPA would see a decrease in costs of $65 million per year if it joined EDAM. But if BPA joins Markets +, its overall costs would rise by $83 million, a net difference of $148 million in costs each year. BPA's internal modeling showed a roughly similar result, with a net cost of $165 million per year if BPA chooses Markets + instead of EDAM.

NEW GOVERNANCE STRUCTURE SET FOR THE WESTERN MARKETS

One of the driving issues for BPA, and presumably for other utilities, is the governance structure of the Western markets. EDAM has been viewed as too heavily influenced by California and CAISO, but two recent changes have created a new governing structure to resolve this concern.

1. As of July 2025, CAISO no longer has joint authority over the Western Energy Imbalance Market or the Energy Day Ahead Market. The primary authority over these entities is now the Western Energy Markets Governing Body.
2. A new, regional organization is being formed, called the Regional Organization for Western Energy. This body will be "led by an independent board with sole authority to oversee the market functions."

These changes set the stage for new leadership and independent, multi-state governance of electricity markets across the West.

THE BIGGER THE MARKET, THE LARGER THE SAVINGS

EDAM taps into a large fleet of low-cost renewable energy generation, as well as an expansive network of traditional generation sources. The larger the market, the greater the benefits to ratepayers. An interconnected Western market can save nearly $1.2 billion each year, according to an analysis by Energy Strategies. This is more than double the savings from the Western Energy Imbalance Market alone.

Analysis shows that the utilities that have elected to join SPP's Markets + would have saved more money if they had joined the Western market. These results are similar to what BPA and the Brattle Group found: EDAM offers much larger potential for savings.

Deciding which energy market to join is a consequential decision, with large financial ramifications for ratepayers as well as investors. NorthWestern Energy should not only conduct a careful analysis of both options, but should also release the results to the public and incorporate the analysis into its IRP.

REFERENCES AND RESOURCES

BPA Day-Ahead Market Participation Benefits Study, The Brattle Group, 2024

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Electricity Day-Ahead Markets - An explainer from the Oregon Department of Energy

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