THIRD-PARTY ANALYSIS OF REGIONAL ENERGY STUDIES

Work Group Co-Leaders:
Steve Andersen, Clark Public Utilities
Shawn Hil, FortisBC

Work Group Participants:

Mark Bouchard, Enbridge
Jennifer DeBoer, Cascade Natural Gas
Frank Lawson, Eugene Water & Electric Board
Kaitlin Lundquist, Williams NW Pipeline
Jordan McDonough, Williams NW Pipeline
Tom Michelotti, NorthWestern Energy
Kyle Putnam, NW Natural
Connor Reiten, PNGC Power
Brian Robertson, Cascade Natural Gas
Ken Ross, FortisBC
Seth Wiggins, Portland General Electric
Ben Zwirek, Williams NW Pipeline

Contractor:
Guidehouse
Outwit Complexity

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The Pacific Northwest energy landscape is evolving rapidly, with more frequent extreme weather events and increasing energy demand placing new pressures on reliability and resource adequacy. The January 2024 cold weather event revealed the Pacific Northwest's energy system is dangerously close to having insufficient supply and highlighted enhanced coordination between electric and natural gas systems is critical to ensuring a resilient and reliable energy supply.

Industry leaders came together in May 2024 to address the need for enhanced coordination of the gas and electric systems. Although several individual studies examining the changing regional landscape have been conducted in recent years, we identified a need to synthesize these studies to identify a common understanding of how the region is planning to meet demand and assess risks. This bird's-eye view across the analytical landscape could provide insights and recommendations to enhance gas-electric planning and coordination.

To execute on this vital task, we asked Guidehouse to conduct a thorough literature review. Guidehouse synthesized the key findings from relevant studies, including regional forecasts, adequacy assessments, and extreme weather retrospectives. Guidehouse developed gaps and recommendations based on the findings that serve as an essential foundation for improving coordinated strategies for regional planning.

The stakes are enormous – the reliability of energy supply to our customers, the achievement of our clean energy goals, and the continued economic vitality of our region require us to work together on the transition to a clean energy future. By proactively coming together to support this literature review, we are taking a crucial step in building a clearer understanding of what we need to do to secure a more sustainable and resilient energy future for the Pacific Northwest.

With thanks to and on behalf of the work group,

Steve Andersen, Clark Public Utilities and Shawn Hill, FortisBC
Work Group Co-leaders

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NWGA/PNUCC Literature Review Findings Brief

Danielle Vitoff
Darek Imadi
Kaavya Malhotra

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Table of Contents

Slide

Scope and Purpose

Helping inform improvements in gas and electricity sector coordination with the goal of enhancing reliability and resilience at a time of rapid change.

The literature review analyzed 19 studies published by gas and electric organizations to identify common themes and risks associated with rising energy demand and the increasing frequency of extreme weather events in the Pacific Northwest and the broader Western U.S.

Based on this analysis, and input from utility planners involved in the NWGA/PNUCC joint working group, we have developed recommendations aimed at enhancing coordination between gas and electric systems.

The key findings and gaps and recommendations are summarized in the following findings brief for regulators, policymakers, and utilities to better understand the issue.

Table of Studies Reviewed

#	Title	Author	Year
1	2024 Pacific Northwest Loads and Resources Study	BPA	2024
2	Winter Conditions Report for January 2024	CAISO	2024
3	Net-Zero NW: Energy Pathways Technical Report	Clean Energy Transition Institute	2023
4	Northwest Regional Forecast of Power Loads and Resources	PNUCC	2024
5	Pacific Northwest Gas Market Outlook	NWGA	2023
6	Pacific Northwest Pathways to 2050	E3	2018
7	Pacific Northwest Power Supply Adequacy Assessment for 2029	NPCC	2024
8	Analysis of the January 2024 Winter Weather Event	Powerex	2024
9	Assessment of January 2024 Cold Weather Event	WPP	2024
10	2024 Summer Reliability Assessment	NERC	2024

#	Title	Author	Year
11	2023 Long-Term Reliability Assessment	NERC	2023
12	2023 Western Assessment of Resource Adequacy *(Note: Weblink Archived)*	WECC	2023
13	Resource Adequacy in the Pacific Northwest	E3	2019
14	National Gas Reliability: Issues for Congress	Congressional Research Service	2024
15	2023-2024 Winter Reliability Assessment	NERC	2024
16	Year 10 Extreme Cold Weather Event Report	WECC	2023
17	EPRI AI Powering Intelligence	EPRI	2024
18	Kelowna Electrification Case Study	Fortis BC	2023
19	PNW Electric Utilities IRP Comparison Table	Fortis BC	2020

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Literature Review - Key Findings

The studies reveal insights into energy demand projections, resource adequacy, system resilience, and the impact of extreme weather events in the Western region. They reveal the need for gas/electric coordination and regional planning to adapt to a changing landscape.

Theme 1

Key Findings: Demand and Load Growth

1

A significant driver of load growth in the Western Interconnection and the Northwest is the expansion of data centers

Data centers consume large amounts of electricity due to their cooling needs, leading to substantial increases in electricity demand. This expansion is projected to continue in the Northwest, with load increases ranging from 50% to 200% depending on the specific Balancing Authority.

Data center expansion is also being considered and forecast to grow in other areas, such as the Desert Southwest, which could result in a doubling of the share of data center demand by 2030.

2

The projected load growth in the Western Interconnection over the next ten years is almost double the rate reported in the previous year's assessment

The 2023 assessment predicts a 16.8% increase in demand in WECC over the next decade, compared to a 9.6% increase reported in 2022. The PNW is forecasting an increase of over 30% in the next 10 years.

This surge in demand is a primary factor contributing to the growing resource adequacy risks in the region. Data centers, as mentioned in #1, are the major contributor to this increased growth and steep revisions of past projections. High-tech manufacturing and the trend towards electrification are also cited.

3

Electrification policies and trends are contributing to the increase in demand – limited analysis considering implications of direct use of natural gas

The transition to electric vehicles and the electrification of heating in buildings are contributing to the increasing need for electricity. While energy efficiency measures help to offset some of this increased demand, utilities are still forecasting significant load growth in the coming years.

The switch from gas to electric in residential homes will also have a significant impact on peak demand. The value of the direct use of natural gas during extreme weather events and the impact of attachment policies for new customers is an important topic that was not discussed in the studies reviewed.

Theme 2

Key Findings: Resource Adequacy/Reliability

1

Resource adequacy remains a critical risk - planned resources may be insufficient to meet future demand

This risk has increased compared to the previous year. The Western Interconnection faces challenges in meeting future energy demands under various system conditions. The most significant risk factors include substantial load growth, extreme weather, uncertainty in forecasting, and the integration of non-dispatchable resources like solar and wind power.

While short-term projections (2024-2025) for WECC show a minimal number of demand-at-risk hours, the magnitude and frequency of these hours significantly increase from 2026 onward, indicating a shortfall in resource plans.

2

System flexibility is significantly impacted by the increasing integration of variable renewable energy (VRE).

Renewables pose challenges for maintaining a reliable electricity supply. The Variability Margin Index (VMI), a metric used to assess the variability in the resource and load mix, showcases this trend in system flexibility. The VMI has increased substantially between 2022 and 2023 in the WECC due to higher renewable resources, highlighting the growing need for dispatchable flexible resources in the Western Interconnection.

Increasing drought conditions are also responsible for 23% lower hydro generation in the NW, demonstrating heightened risks of climate change on this critical regional resource.

3

Increasing variability coupled with baseload retirements and an increasingly constrained natural gas system pose a challenge to resource adequacy.

Traditional resources can be readily dispatched to meet demand, while variable resources like solar and wind power cannot. The increasing reliance on variable resources, coupled with the retirement of traditional baseload resources, makes it challenging to ensure a consistent energy supply under diverse conditions.

As coal plants are retired natural gas is increasingly being relied upon as a flexible generation resource. However, existing natural gas infrastructure, such as interstate pipelines that are at times reaching 95% utilization, are becoming increasingly constrained. New natural gas infrastructure will need to be developed in coming years to accommodate new generation.

Theme 3

Key Findings: System Resilience and Flexibility

1

Natural gas generation flexibility is critical in maintaining grid resilience

The Western Electricity Coordinating Council (WECC) modeled a simulated extreme cold weather event in 2033 to understand the impacts on the system, determining that the Western Interconnection experienced load shedding when natural gas derates were modeled signifying the reliance on natural gas during extreme events.

2

Natural gas generation will be a needed resource for system resilience and flexibility even under a decarbonized grid

Natural gas is required to provide firm capacity not met by variable renewables, even under up to a 98% decarbonization scenario in the NW. As variable renewable energy use increases, gas generation will become crucial in avoiding loss-of-load events.

Natural gas generation capacity factors are forecasted to decline over time in these decarbonization scenarios but remain cheaper than relying on other forms of firm generation or energy storage.

3

Enhancing system resilience requires addressing vulnerabilities related to natural gas fuel supply

The critical role of natural gas generation hinges on a functioning natural gas system. The 2024 cold snap and Winter Storms in Texas underscored the need for more resilient natural gas infrastructure. Fuel assurance is vital for grid stability and reliability during extreme weather events. To mitigate fuel-related risks, proactive emergency planning, infrastructure hardening, improved gas-electric communication, and increased natural gas supply resources are essential.

Theme 4

Key Findings: Gas/Electric System Interdependence

1

The increasing interdependence of systems necessitates enhanced coordination to mitigate the risk of cascading failures.

The growing reliance on natural gas-fired generation to meet peak demand and compensate for the intermittency of renewable energy sources necessitates increased coordination between gas and electric utilities to ensure the reliability of both systems. Emerging technologies, such as hybrid-heating systems, should be jointly explored especially in infrastructure-constrained areas as they can yield significant cost savings through peak shaving.

2

Gas-Electricity Coordination is hindered by regulation misalignment

Misalignment between natural gas and electricity markets poses significant challenges to efficient coordination and reliability.

Incompatibilities in contracting practices, scheduling discrepancies, and insufficient infrastructure investment incentives hinder the ability of power generators to secure reliable gas supplies, and natural gas companies from making necessary midstream infrastructure investments, underscoring the urgent need for market reforms in certain energy markets.

3

Siloed planning in gas and electric systems, has a detrimental effect on overall energy reliability

Planning often occurs in isolation from considerations related to natural gas supply and transportation.

Similarly, efforts to electrify building heating and other end uses that traditionally rely on natural gas must consider the capacity limitations of existing gas infrastructure for delivery to power.

Theme 5

Key Findings: Extreme Weather Events

1

Natural gas played a vital role in maintaining electricity supply during extreme cold snaps

During the January 2024 cold snap, the natural gas system satisfied 70% of end-use energy demand during the peak hour of this event in the PNW. The Western Electricity Coordinating Council (WECC) modeled a similar extreme cold weather event ten years in the future (2032) and found that natural gas generation was needed to meet load. When natural gas derates were modeled, load shedding occurred, demonstrating the reliance on natural gas during these events.

2

Improve the quality of forecasting load during extreme weather is critical for ensuring resource adequacy

Extreme weather events, especially those involving extreme cold, can cause electricity demand to deviate significantly from historical forecasts. This is partly due to the growing electrification of the heating sector, which makes demand more sensitive to temperature changes. Underestimating demand ahead of extreme weather events can lead to insufficient resource scheduling and potential reliability issues.

Theme 6

Key Findings: Regional Planning

1

Prioritize collaborative regional planning efforts

Numerous studies highlight the critical need for improved regional coordination and collaboration to tackle the complex challenges related to resource adequacy and grid reliability, especially considering the increased interdependence of gas and electric systems following the significant rise in natural gas generation capacity over the past two decades.

Current planning processes are inadequate given the evolution of the energy system.

2

Incorporate extreme weather and fuel security in planning

With increasing frequency of extreme weather events, cold and hot, the supply and demand for electricity and natural gas is disrupted, leading to reliability challenges.

Planners must incorporate better scenario planning and robust strategies to enhance resilience to these events including weatherization and hardening, fuel assurance plans especially for natural gas, and emergency response capabilities between gas and electric systems at an operational level.

3

Address uncertainties forecasting load growth – in particular, data centers

Data centers and electrification of buildings and transport represent a significant and rapidly growing source of electricity demand in the region. This growth and the uncertainties forecasting it adds to the pressure on the grid and presents challenges for resource adequacy planning.

Regional planning must proactively address the implications of data center expansion and electrification by implementing better data sharing, coordinating planning, and encouraging energy efficiency, demand management, adequate transmission infrastructure, and strategic siting.

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Planning Implications for Gas-Electric Utilities

Gaps, and Recommendations

From these studies, we have identified gaps in electric and gas sector planning and highlighted corresponding recommendations to improve coordination and preparedness.

Planning Implications: Gaps

Varying gas and electric sector approaches to forecasting loads from electrification, data centers, demand side resources, and evolving consumer behavior drive uncertainty in planning

- Current load forecasting methods used by PNW utilities often fail to adequately account for the impacts of electrification. Only 40% of PNW Balancing Authorities directly incorporate electrification assumptions in their forecasts.
- Differing planning assumptions, data inputs, and granularity between gas and electric utilities in the region hinder effective coordination and comparisons of forecasts.
- Utilities differ in how they forecast demand response programs and customer participation, not just passive load. Some consider demand response as a supply-side resource while others treat it as load modifying. This lack of transparency limits broader alignment amongst entities.
- The direct use of natural gas in buildings is a key factor in meeting baseline demand and peak loads but is often overlooked in studies. Current approaches do not fully account for its impact, creating gaps in demand projections. Electrification efforts must better consider how transitioning direct-use gas customers affects total load growth, peak forecasting, and grid reliability.

Insufficient understanding of peak demand and how gas/electric entities can jointly manage peak events

- Electric and gas utilities lack a clear understanding of how both sectors interact during peak events, in addition to how electrification and extreme weather will impact peak energy demand in each respective system.
- Peak events manifest differently and have distinct resource needs for gas and electric systems. For example, the gas system may experience a sharp single day peak driven by space heating demand while the electric system may face a multi-day capacity challenge during a prolonged cold weather event. Analyzing the varied nature of peak demands and how they are mitigated across the sectors is important for understanding the most efficient mitigation solutions. Gaps also exist in quantifying and incorporating such solutions into planning processes.
- Electric and gas system planners don't have a way of looking at coincident peak impacts on their systems under both extreme weather and end-use changes, and thus how to invest in different kinds of technology.

Planning Implications: Gaps

Planners have obscured visibility of gas-electric interdependencies

- Gas and electric system planners often lack detailed visibility and data into the constraints, performance, and interdependencies of the other sector, making it difficult to accurately assess resource adequacy and identify potential risks.

Traditional planning metrics are insufficient in capturing new risks

- Metrics like planning reserve margins (PRMs), which measure the amount of capacity above forecasted peak demand, fail to account for the energy limitations of VERs, fuel supply risks, and the impact of extreme weather events on resource availability.
- Traditional resource adequacy models, often based on a loss-of-load event (LOLE) of 1 day in 10 years, may not adequately capture the risks associated with more frequent and severe extreme weather events. These events can simultaneously impact both demand and resource availability, leading to extended periods of high risk.

Lack of a framework to measure and optimize the full value and affordability of energy services that customers receive

- There is a lack of an integrated perspective on how to best serve customers' total energy needs across all sources. When gas and electric planning are siloed, the focus on optimizing overall delivered energy value to customers is often lost. Separate gas and electric planning processes, often governed by distinct regulatory models, typically aim to maximize value for either gas or electric ratepayers rather than the total cost and quality of energy services delivered. This leads to suboptimal resource choices and missed opportunities for synergy.
- Current planning approaches and regulatory constructs are not well suited to comprehensively evaluate tradeoffs and complementarities across the gas and electric systems.

Planning Implications: Recommendations

Facilitate better coordination and collaboration between gas and electric entities by establishing cross-sector platforms and forums that actively develop and recommend planning assumptions or methodologies

- Regular forums that convene gas and electric utilities, pipelines, ISOs/RTOs, and other stakeholders to share information, align planning assumptions, and develop solutions can meaningfully advance coordination. Existing forums like the PNUCC/NWGA working group should be leveraged and expanded to serve this function. Leverage regional bodies, conferences, and other forums as venues to recommend and implement enhanced gas-electric coordination initiatives.

Promote enhanced operational data sharing between gas and electric utilities to improve system resilience

- Promote routine operational data sharing through joint platforms, regular coordination meetings, and standardized data formats/protocols. One notable example is in the Northeast where the NE-ISO decided to provide day-ahead hourly dispatch data from power plants to gas system operators to help them better plan for loads and ensure natural gas system integrity.

Engage stakeholders on benefits of assessing overall energy value instead of siloed gas vs. electric perspectives

- Partner on developing accessible tools and guides that empower stakeholders to evaluate holistic energy value. Dialogue should be facilitated with consumer groups, environmental advocates, and policymakers on integrated value frameworks.
- Articulate customer, reliability and cost benefits of more holistic gas-electric planning to regulators and policymakers. Fact-based, data-driven case studies and whitepapers that quantify benefits can build support. Examples could include peak demand reduction, consumer savings, improved grid resilience from backup fuel capability, and gas and electric rate stability from coordinated infrastructure build.

Planning Implications: Recommendations

Jointly plan and collaborate on understanding load growth and peak mitigation options

- Planners and policymakers need to better consider a range of peak mitigation options like hybrid heating across gas and electric sectors. For example, hybrid gas-electric heating systems, if aggregated and dispatched effectively, could provide significant peak reduction value for the electric system while creating more manageable gas demand. Developing a shared understanding of these options and their associated infrastructure needs, operational coordination requirements, and market structures can unlock significant value.
- Inputs used for load forecasting should be improved and better aligned across entities to more accurately account for the impact of load growth.
- Develop new techniques and utilize information beyond historical data to model decarbonization and increasing frequency of extreme weather.
- Improve point load forecasting techniques to anticipate future data center, manufacturing, and other large load growth.

Better integrate gas and electric planning processes by reducing barriers and designing new models

- Utilize or develop coupled gas-electric models to better understand system interdependencies. Modeling tools that can stress test gas and electric systems under a range of future demand and weather cases can identify key vulnerabilities and quantify the value of solutions like demand response, storage, and inter-regional transmission. Partnerships between gas and electric utilities, universities, national labs, and vendors should be formed to advance this research.
- Identify changes needed to regulatory models and planning processes to enable more holistic, integrated approach optimizing customer value. Potential evolutions could include aligning gas and electric utility revenue models, mandating joint gas-electric planning studies, creating new customer energy service metrics, and enabling co-optimized gas-electric operations. Regulators should engage stakeholders to assess barriers and design new models.

Planning Implications: Recommendations

Establish tools and frameworks for quantifying the full value of gas-electric interdependencies

- Develop metrics to quantify reliability and resilience value of gas-electric coordination. Candidate metrics could include probability of coincident gas-electric system failure and customer outage costs. Standard calculation methodologies should be developed and benchmarking efforts undertaken.

Adopt more robust reliability indicators that go beyond traditional metrics

- Loss of load metrics and planning reserve margins need to evolve to better reflect energy limitations of renewables, fuel supply risks, and weather impacts. New techniques such as effective load carrying capability for wind and solar and convolution of fuel disruption probabilities are needed. Scenario-based planning that captures correlated outages across resources should complement traditional Monte Carlo simulations.

Align planning and regulatory approaches to mitigate policy whiplash

- Policymakers should strive for durable, long-term policy frameworks that reduce investment risk. Varying policy approaches at different government levels (i.e. city, county, state) and lack of long-term clarity is a key planning challenge. Abrupt shifts in federal, state or local policies around issues like building electrification, renewable tax credits, and gas hookup moratoriums create significant uncertainty for utility planners.
- Explore approaches to de-risk and depoliticize energy system planning to improve investment certainty. Potential strategies include formalizing long-term resource and reliability targets in legislation, using independent expert panels to set planning assumptions and study methodologies, and creating accountability mechanisms. Best practices should be researched and socialized.

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Demand and Load Growth

Electricity demand growth has outpaced estimates and magnitude of future increases are uncertain. Demand uncertainty is a challenge for energy planners.

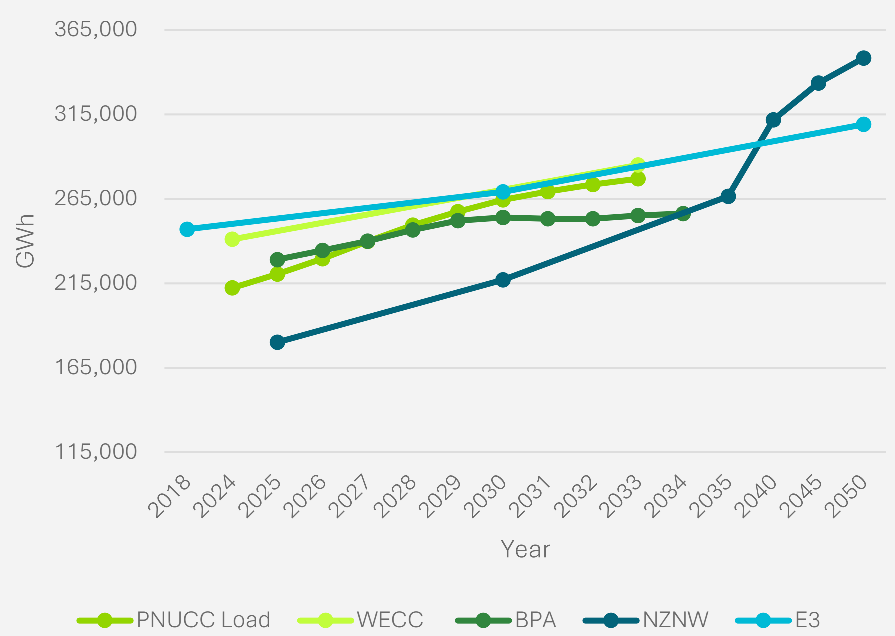
Electricity demand is set to more than double previous projections

- **Studies anticipate significant increases in both annual energy demand and peak demand, though <u>total</u> demand will increase at a faster rate.**[1, 3, 4, 6, 12]
    - WECC projects a 16.8% increase in total energy demand over the next 10 years, nearly double the growth projected in 2022.[12]
    - In the NW, specifically, aggregated utility forecasts show demand could rise by over 30% in the next 10 years, from 23,700 aMW in 2024 to 31,100 aMW in 2033.[4]

- **Data center expansion is identified as a primary driver of the increasing future load growth projections between 2022 and 2023, with the Northwest region experiencing the most substantial increases.**[4, 7, 12, 17, 13]
    - Northwest Balancing Authorities (BAs) project potential load increases of 50% to 200% depending on the specific BA. [12]
    - The NPCC adequacy assessment highlights a scenario where higher data center loads result in exceeding 41,000 MW at peak system needs.[7]

- **The push toward electrification is another significant driver. Electrification of transport expected to add more load than buildings in the short-medium term.**
    - New projections reflect electrification policies such as Washington's updated energy codes.
    - Increased demand from charging EVs is projected to approach 4% of total load in the NW by 2034. [4]
    - Forecasting impact of electrification is a challenge across the board. Utilities in WECC have different planning process to estimate impact of electrification on load growth.[12]
    - Only 40% of BAs in the West incorporate electrification assumptions directly into their load forecasts. Another 40% consider electrification as a separate forecast.

NW Electricity Demand Forecast by Study



- *Differences in total demand can be attributed to varying definitions of "Northwest" geography and forecasting approaches*
- *Evolved Energy and E3's forecasts assume scenarios in which long-term decarbonization goals have been achieved with heavy electrification, whereas PNUCC/WECC/BPA examine 10-year projections*

Case Study:

Data Centers

% of total state electricity consumption attributed to data centers

Region	State	2023	2030			
		Present	Low	Moderate	High	Very High
Pacific Northwest	Idaho	0.57%	0.68%	0.74%	1.03%	1.40%
	Oregon	11.39%	13.39%	14.43%	18.93%	24.14%
	Washington	5.69%	6.77%	7.34%	9.88%	13.00%
Desert Southwest	Arizona	7.43%	8.81%	9.53%	12.73%	16.58%
	California	3.70%	4.43%	4.81%	6.54%	8.70%
	Nevada	8.69%	10.28%	11.10%	14.75%	19.07%
	New Mexico	1.48%	1.78%	1.94%	2.66%	3.60%
Rocky Mountain West	Colorado	2.66%	3.18%	3.46%	4.73%	6.34%
	Montana	3.71%	4.43%	4.81%	6.54%	8.71%
	Utah	7.68%	9.10%	9.84%	13.13%	17.08%
	Wyoming	11.26%	13.24%	14.27%	18.73%	23.90%

Sources: EPRI

- Data center electricity consumption has reached approximately 5-11% of total electricity consumption in PNW state in 2023 and under a high growth scenario share of demand could grow to more than 13-24% of demand by 2030. [17]
- This emphasizes the already significant contribution of data centers to regional electricity demand, and uncertainty of future scale of growth.

- High data center load growth is a major risk in the projected energy shortfalls in the Northwest. [7]

- Data centers are a major driver of increasing load growth in all demand forecasts, especially in the Northwest
  - The expansion of data centers will cause greater electricity usage in the next several years (17% load growth according to NERC), with recent assessments being much higher past predictions.[11]
  - NPCC predicts 2,400 aMW-4,000 aMW of new load in the NW due to data centers and chip fabrication, much higher than the 261 aMW predicted by the 2021 Plan. [7]
  - NPCC data center reference forecast falls between EPRI's moderate and high load growth scenario.[7]
  - Data centers are identified as the primary cause for the increase in demand projections between 2022 and 2023 WECC Resource Adequacy assessment

- **The relatively flat demand profiles of data centers mean they have a greater effect on annual energy than on peak demand**. While data centers consume a lot of energy throughout the year, their demand remains relatively stable and insensitive to changes in temperature. This contrasts with loads like building electrification, which have a more pronounced effect on peak demand.

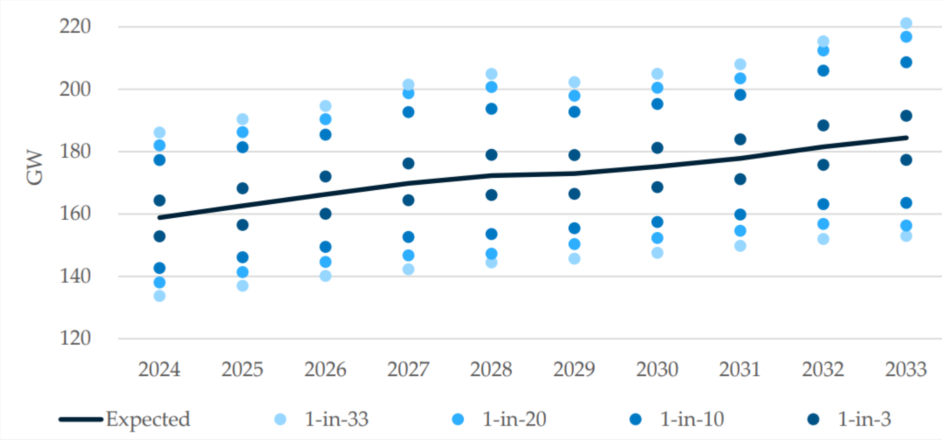
Uncertainties in expected peak demand and the pace at which demand will grow makes it difficult for entities to plan system adequately

- In the summer, the Western Interconnection's peak demand is projected to be 159 GW, but under a heat event, it could be as high as 186 GW. By 2033, this variability only increases, with peak demand expected to be 184 GW, but a 3% chance it is above 221 GW.[12] This increasing uncertainty means that entities need to be prepared for far higher peak demands.

- **Extreme weather conditions, which are likely to increase the coming years, are changing the peak demand profile of the region, which increases the risk of resource shortfalls.**
    - They will increase uncertainty in peak demand forecasts, which will make it more difficult for entities to prepare for future loads. From 2024 – 2033, the uncertainty range in summer peak demand will increase from 27 to 37 GW.[12]
    - Summer and winter extreme weather events will shift the shape of electricity consumption profiles away from peak periods.[7,11]
    - Extreme summer conditions are also increasing in frequency and are expected to change the NW from a traditionally winter-peaking area into a dual-peaking area. [12]

- **There are large uncertainties regarding the pace at which demand will increase, making it difficult for entities to plan accordingly to prevent resource shortfalls. Adequacy threatened under specific scenarios.**
    - If data center load growth accelerates faster than current projections, demand will surpass available resources and all reliability metrics measured by the NWPCC will be violated. The region will be at risk during both the winter and the summer. [7]
    - If energy efficiency improvements do not occur as expected, there will be higher risk of resource inadequacy during the winter region. [7]

Western Interconnection Summer Peak w/ Uncertainty Ranges



Source: WECC

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Resource Adequacy and Reliability

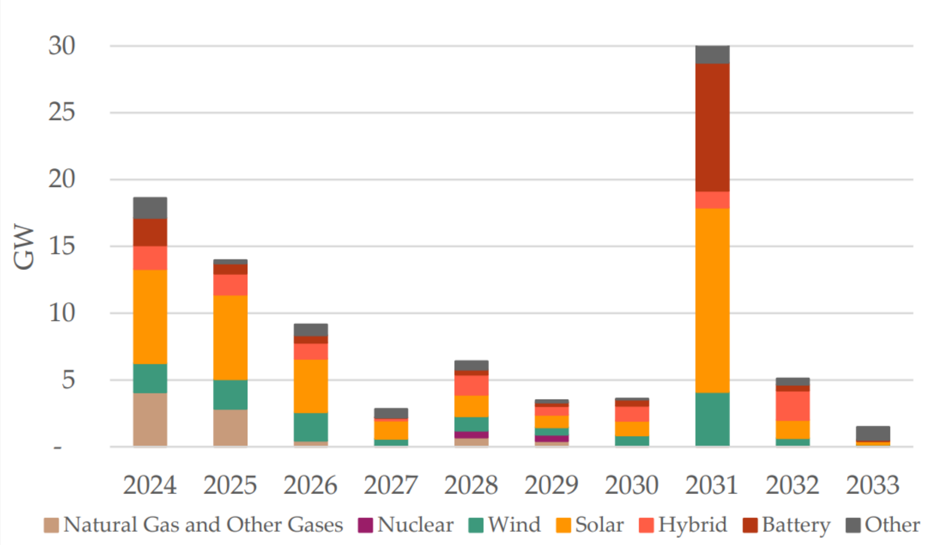
Planned resource additions may be insufficient to keep up with the expected increases in load. The anticipated increase in variable resources will also create more unreliability on the system.

Renewable additions and coal retirements lead changes to the resource portfolio in the coming years, although these plans may be impacted by resource adequacy concerns

- Northwest utilities plan to add 29 GW of new resources over the next decade to keep up with increasing demand, most of which are wind, solar, and battery resources.[4]
  - This pattern matches additions from 2020-2025. Wind has accounted for 36% of new additions, solar 25%, and storage 16%.[4]
  - Battery energy storage system (BESS) capacity in the WECC (excluding CAISO) is projected to reach 18.8 GW by the end of 2025, a 38 % increase from the 13.6 GW at the end of 2024 according to S&P.
  - These plans may be disrupted by the long interconnection queue, supply chain delays, and project approvals.[4, 12]

- Planned coal retirements are also projected to continue, although they are slowing down due to resource adequacy concerns
  - In the NW, 730 MW of coal is expected to be retired in the near-term (2024-2025) and 660 MW in the long-term (2029-2033). 100 MW of natural gas is expected to be retired by 2033.[7]
  - To reduce resource adequacy risks, some retirements are being delayed. A comparison between 2023 and 2022 resource plans for WECC entities shows that there was an increased delay in coal and natural gas retirements.
    - In 2022 IRPs, for example, nearly 8,000 MW was planned to be retired in 2025, whereas in 2023 IRPs, only 4,000 MW is planned to be retired in 2025.[12]
  - In some cases, coal plants are being converted to natural gas plants which are helping to provide an adequate system such as Jim Bridger 1 & 2 and Valmy 1 & 2 in the NW.[12]

Resource portfolio of the WECC



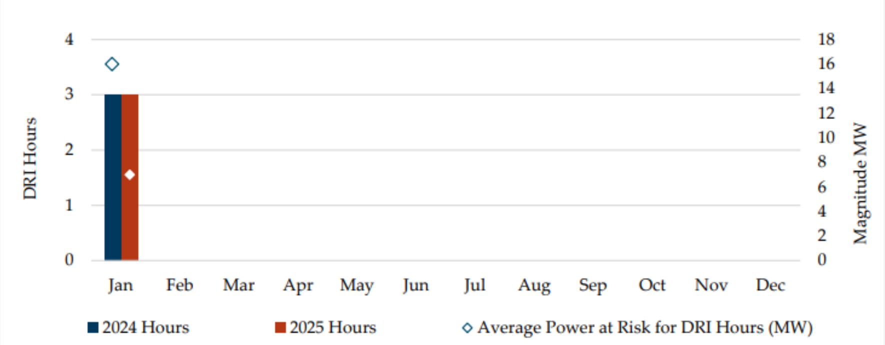
Source: WECC

With high renewable penetration projected, low generation events are more likely to occur, increasing the likelihood of loss-of-load conditions

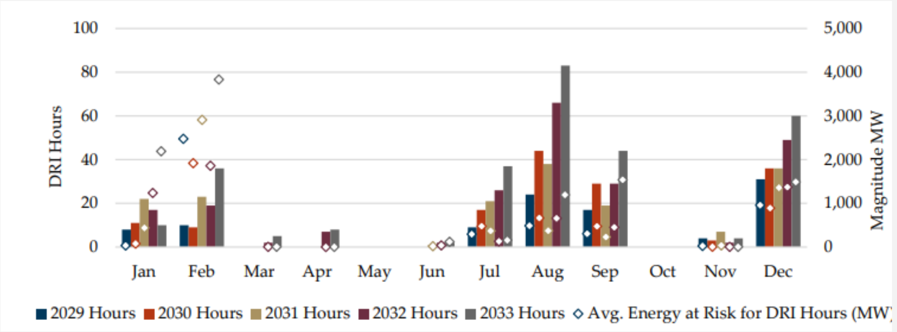
- Renewable resources are limited by weather patterns and have much higher capacity than actual energy produced. With bad conditions, over 100 GW of installed capacity can produce less than 10 GW.[12]
- **As variable resources like solar and wind become primary sources of electricity, low generation events are more likely to occur**. If these events are not considered during resource planning, variability in weather patterns will cause multiday loss-of-load. **With high renewable penetration, low generation will usurp drought hydro conditions as the biggest threat to loss-of-load events.**
  - The number of demand-at-risk (DRI) hours in the WECC is expected to greatly increase In the coming decade. This indicates that planned resources will be insufficient to meet the expected levels of demand and demonstrates the higher likelihood of loss-of-load events. In the NW, specifically, resources will need to keep up with high levels of demand growth expected in the next two years.[12]
  - The variability margin indicator (VMI) was found to increase over the next 10 years. The WECC Resource Adequacy Assessment found a much greater risk in variability in the WECC in 2023 compared to 2022 due to increases in planned variable resources from roughly 20% to 27% until 2030. Although capacity is expected to increase by 95 GW by 2033, the energy from these (mostly) variable resources is expected to increase by 15 GW. [12]
- Some studies modeled that it would be expensive to rely on renewable overbuild to increase capacity and decrease the chances of loss-of-load events occurring. Instead, coordination with natural gas can allow for more reliable energy production.[7, 13]

Demand at Risk Hours (DRI) for WECC

2024-2025



2029-2033



Source: WECC

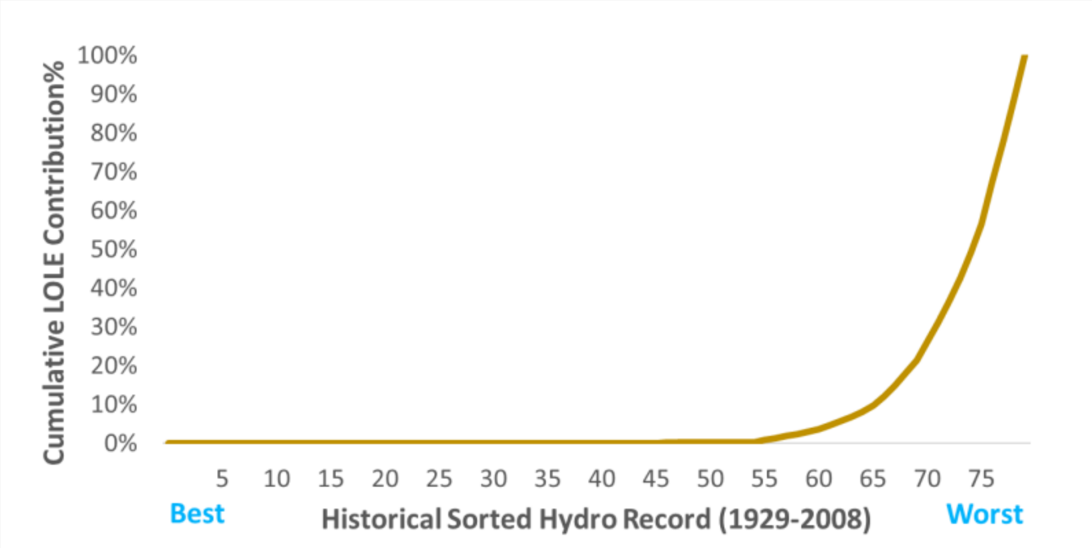
Increasingly unreliable hydropower due to droughts

- The impact of recent droughts in the NW on electricity generation is a warning of lower generation that could occur as drought conditions increase due to climate change
  - According to the EIA, the NW relies on hydropower generation for 43% of its electricity needs. With the region experiencing a drought, water supply at dams has reached less than 75% of normal levels in several counties this year.
  - Recent drought conditions have caused reservoirs to have limited capacity and have lowered hydropower generation in 2024 to 23% lower than the 10-year average.
  - Water at The Dalles Dam, an indicator of water supply conditions in the Columbia River, was 74% of the 30-year normal at the end of September 2024.
  - Reservoir storage at the end of September was at 48% of capacity in OR, 67% in WA, 76% in MT, and 60% in ID.

- It is projected that the worst 25% of hydro conditions would be responsible for nearly all loss of load events in the region. If drought conditions continue to lower hydro generation, the risk of reserve shortfall and number of loss-of-load events (LOLEs) will increase.[11, 13]

- As electrification occurs, low hydro conditions should cause fewer LOLEs (low solar and wind generation, on the other hand, will cause more), but they will still lead to some unreliability. There is a heightened risk for resource shortfall in the winter, as cold weather could cause extended periods of low hydro, solar, and wind generation coupled with high demand.[12,13]

Loss-of-load under various hydro conditions



Source: E3

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System Flexibility and Resilience

Natural gas can be used as a firm resource to improve reliability and resilience, although further planning is required to ensure the system is able to support peak demand.

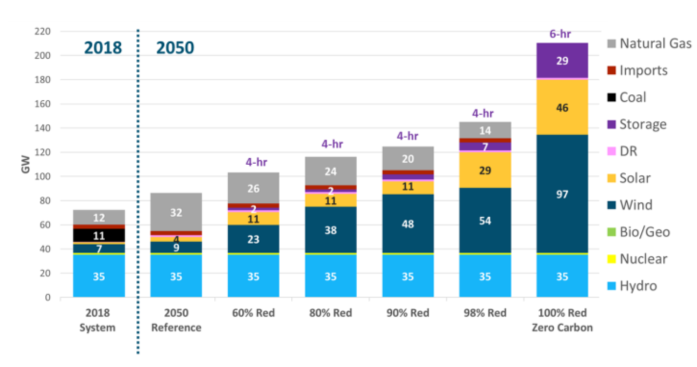
Natural gas will continue to be needed to provide grid flexibility even under deep decarbonization scenarios

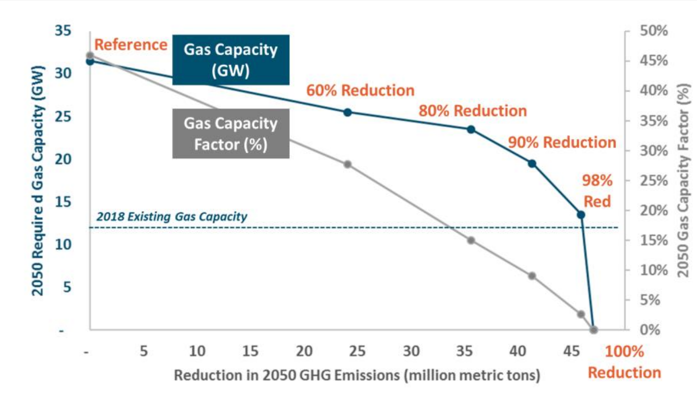
- Across all modeled scenarios, renewables need to be accompanied by firm resources to serve the remaining incremental peak load. To ensure reliability, electricity cannot rely on a single system. **Even under scenarios with 98% decarbonization, natural gas is required to provide reliability, providing the bulk of firm capacity not met by variable renewables.** It is necessary to continue serving load and prevent load shedding.[13]

- **Natural gas is the most cost-effective solution to address capacity challenges, even under deep decarbonization**. It is a more cost-effective and reliable source than alternative options such as battery storage or pumped-hydro, especially during low variable generation and high demand events such as extreme cold events. It also was found to **be a more effective option than renewable overbuild**, which would be costly and could still be unreliable during extreme weather events.[13]

- **As electrification increases, it is modeled that natural gas will transition towards being primarily used to avoid loss-of-load events during low renewable generation events.** Gas will be used sparingly but will need high capacity to ensure reliability, leading to capacity factors as low as 3% under 98% decarbonization scenarios for natural gas plants. To create this high capacity, the addition of new gas generation capacity is necessary even under deep decarbonization. [13]

Generation portfolios and natural gas capacity for various stages of decarbonization



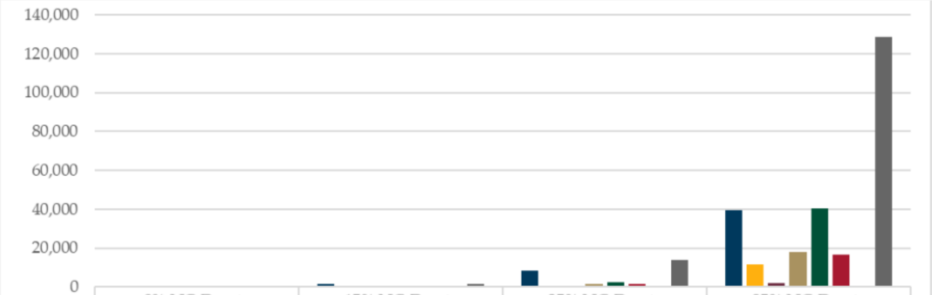


Source: E3

Natural gas generation will be a needed resource for ensuring system resilience and flexibility

- **The reliability of the electric grid will continue to be dependent on the natural gas system during peak load events well into the future. The NW is the most vulnerable to loss of load. Southern WECC less suspectable.**
  - WECC projecting out the 2022 Cold snap out to 2032 found that any loss of natural gas load would result in unserved load across the region.[16]
  - With all natural gas generators operating, there was no load shedding. However, when natural gas availability was reduced by 15%, 25%, and 35%, load shedding occurred in Alberta and other regions.[16]
  - Highest loss of load occurs in the NW at 40,228 MWh under a 35% natural gas derating scenario.[16]
  - While batteries helped to reduce unserved load hours, they were insufficient alone to mitigate natural gas derating.[16]
  - The study highlights the Western Interconnection's dependence on natural gas generation during extreme weather, even with the transition to renewable generation and energy storage.[16]

Total unserved load by region during simulated 2032 cold snap and NG Capacity Derating Scenarios (MWh)



	0% NG Derate	15% NG Derate	25% NG Derate	35% NG Derate
AB	0	1,511	8,309	39,414
BC	0	0	0	11,433
BS	0	0	0	2,148
CA	0	0	1,476	17,794
NW	0	0	2,464	40,228
RM	0	0	1,375	16,619
SW	0	0	22	754
Total	0	1,511	13,647	128,390

Sources: WECC

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Increasing reliance on natural gas to meet peak electricity demand raises concerns about the adequacy of natural gas infrastructure - new vulnerabilities planners must consider

- The increasing use of natural gas for electricity generation, in response to the increasing deployment of renewables, raises concerns about whether the region has enough natural gas infrastructure to support the level of real-time flexibility needed to respond quickly to fluctuations in renewable energy supply. [7,12,13,14,16]
- In 2020, three Western states reported that growth in the use of renewable energy could add stress to the natural gas pipeline system if there is not enough pipeline capacity to transport the increased volumes of natural gas needed for power generation. [14]
  - **Average utilization of interstate pipelines in the Pacific Northwest has exceeded 95% in recent years** and is expected to grow during normal winters. [5, 14]
- **Disruptions in one system can cascade to the other**, as seen during Winter Storm Uri in Texas, where the **loss of electricity impacted natural gas production and distribution**, further exacerbating power outages.
- From 2010 to 2019, there were 1,800 reported disruptions on interstate natural gas transmission pipelines. These disruptions were varied in nature but highlight potential vulnerabilities in the natural gas system that need to be assessed. [14]
- The multi-day cold snap in January 2024 was aggravated by constraints in the natural gas system. A fiber optic cable failure at the Jackson Prairie Natural Gas Storage Facility led to reduced system inventory for gas companies in the NW and BC, prompting a curtailment watch. [2]

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Gas and Electric System Interdependence

To prepare for these changes to the system and avoid system shocks, there must be enhanced planning coordination between gas and electric systems.

Studies repeatedly highlight growing interdependence necessitates changes to current planning processes and commercial structures

- **Increasing interdependence can lead to failure cascades**: The electric grid relies on natural gas for reliable generation, especially during peak demand periods and when renewable energy output is low. This dependence is expected to grow as older thermal generators retire and are replaced with a mix of renewables and natural gas plants. However, the natural gas system itself relies on electricity for operation, particularly for powering compressors and other critical infrastructure. This creates a complex interdependence, where disruptions in one system can cascade into the other. [14]

- **Traditional metrics, such as Planning Reserve Margins, are insufficient for systems increasingly dependent on variable energy resources and just-in-time natural gas delivery.** To address this, gas and electric entities must collaboratively develop advanced planning tools and models. Key considerations include accounting for both peak and non-peak load hours, incorporating probabilistic assessments of energy risks like fuel supply limitations and extreme weather events, evaluating interregional transfer capabilities, and considering the operational flexibility of diverse resources, including natural gas generation, renewables, and energy storage. Moving to modeling platforms that co-optimize both the natural gas and electric systems is also recommended. [4,7,11,13]

- **Market misalignment:** The structure of gas and electricity markets can create barriers to efficient coordination. Differences in scheduling practices, trading requirements, and pricing structures can complicate gas procurement for power plants and hinder investment in new gas infrastructure. [14]
  - **Contracting structures** hinder power generators' ability to secure necessary pipeline capacity for reliable fuel supply. Power plants often need to quickly adjust their natural gas consumption based on fluctuating electricity demand. However, the lack of efficient **pricing mechanisms for intraday volumetric variability** makes it difficult for them to procure gas transportation services that meet this need. [14]
  - **Pipeline capacity expansion**: Conversely, the structure of competitive wholesale electricity markets does not adequately incentivize generators to invest in the capital-intensive expansion of gas transportation infrastructure which poses reliability risks. [14]

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Impact of Weather Events

Recent extreme weather events highlight the gaps in system planning that will limit gas and electric entities' ability to support higher demand with a changing resource portfolio.

Case study

January 2024 Cold-Snap

This extreme cold weather event provides an example of future system shocks that may occur if there is insufficient planning for extreme weather events.

- Near-record low temperatures across the PNW contributed to high demand requiring around 4900 MW of imports from the Southwest and Rockies during peak demand hours. Peak demand during this period was not exclusive to peak hours.[8, 9] These levels of high demand are an indicator of future unpredictable demand profiles that may be seen with increased extreme weather events.
- During the cold snap, low temperatures caused low hydro generation, which limited fuel supply and meant that utilities were not able to provide sufficient capacity to meet peak demand. [8, 9] This demonstrated the risk of heavy reliance on variable energy resources to provide capacity during moments of peak demand and highlighted the need for available dispatchable resources to avoid resource shortfall during these events.
- There was significant reliance on inter-regional imports to support the cold snap. Despite this, transmission was limited by a preplanned forced outage on the NV-OR border.[2] Congestion also caused outages and limited import capability. [2, 8, 9]

Observed load for 12 BAs during January 12 – 16 relative to peak loads during the last 10 years

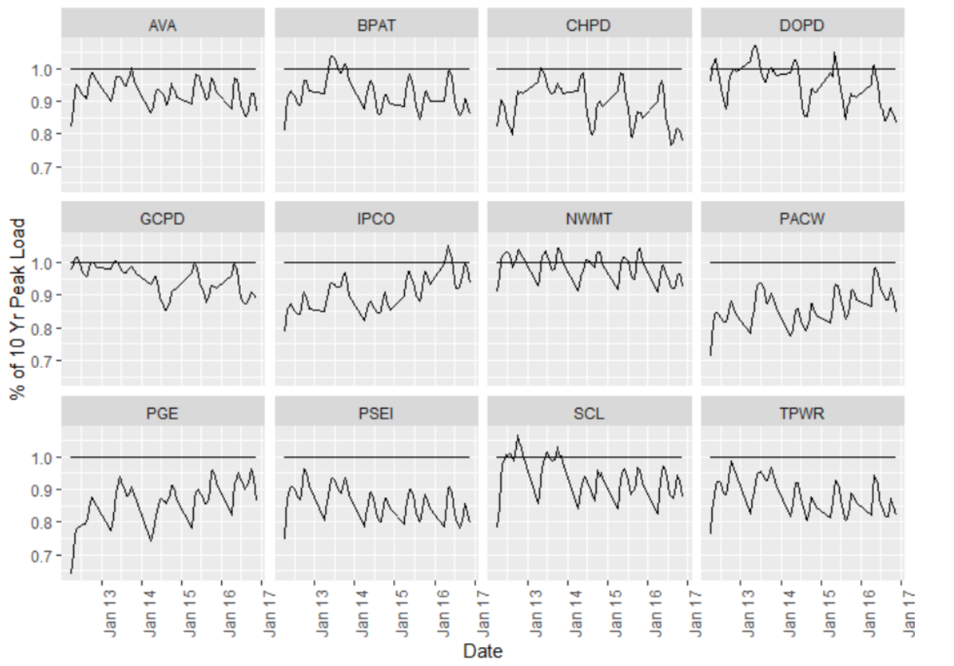

Figure 3 - The observed load for 12 BAs during January 12 – 16, 2024 (trend lines) relative to their peak loads (horizontal line at 1.0) during the winter for the last 10 years (Source: U.S. Energy Information Administration (EIA) - Real-time Operating Grid [select download data -> Balancing Authority/Region Files])

Source: WPP

During the event, peak demand was not exclusive to peak hours and came close to, or crossed, in some instances, the average winter peak loads for the last 10 years.

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