Impacts of Lower Snake River Dam Removal and Increased Spill Requirements on Costs, Carbon Emissions, and Reliability

Final Report

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ENERGYGPS CONSULTING LLC

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1 Glossary

- **AC / DC:** Alternating Current / Direct Current
- **Baseload:** Continuous energy demand in a region; level below which demand never falls
- **BPA:** Bonneville Power Administration, federal agency in charge of operating hydro-electric dams in the Pacific Northwest
- **Capacity factor:** the percentage of time the generator is available to produce electricity upon demand
- **CAISO:** California Independent System Operator balancing authority
- **CT:** combustion turbine units
- **Deliverability:** In the natural gas business refers to the amount of natural gas that can be delivered by a natural gas local distribution company via both pipeline and storage withdrawals
- **Dispatchability / dispatchable generation:** sources of electricity that can be dispatched on demand at the request of power grid operators, according to market needs.
- **EIA:** U.S. Energy Information Administration
- **Fleet:** the aggregate supply of generators
- **GTN**: Gas Transmission Northwest natural gas pipeline
- **GW:** Gigawatt; equivalent to 1,000 megawatts (MW)
- **GWh:** Gigawatt-hours
- **Heat Rate**: The conversion efficiency of a natural gas plant – it is the number of MMBtu required to produce a MWh of electricity or simply MMBtu per MWh
- **ICE:** Intercontinental Exchange, publisher of commodity price index reports
- **Implied Heat Rate**: Comparative ratio calculated by dividing the electricity price by the natural gas price. If the implied heat rate drops below a gas plant's heat rate, then the cost of buying gas to make electricity exceeds the value of the electricity itself.
- **kcfs**: kilo cubic feet per second (rate of river water flow)
- **LCRD**: Lower Columbia River Dams
- **LDC:** natural gas local distribution company
- **Load**: Demand for electricity
- **Load-serving entities:** Often utilities; entities that provide electric service to individual and wholesale consumers
- **Load shed:** Power demand reduction
- **LSRD**: Lower Snake River Dams
- **Malin:** Gas trading hub near the California-Oregon border

- **Mid-C:** Energy trading hub near the Washington-Oregon border
- **MMBtu:** Million British thermal units (measures natural gas quantity)
- **MWh:** Megawatt-hours
- **Nameplate capacity:** the maximum output rating of a wind generator
- **NERC:** North American Electric Reliability Corporation
- **Net load:** defined as load minus wind and solar generation
- **NWP:** Natural gas pipeline
- **NWPP:** Northwest Power Pool (Northwest sub-regional balancing authority)
- **Pacific Northwest market:** For the purposes of this study, Oregon and Washington
- **Peaker:** Flexible and nimble generators that can turn on and off quickly ("fast start") in response to need, most often combustion turbine (CT) units fueled by natural gas
- **Reliability event:** (see "Scarcity event")
- **Resource adequacy (RA) program:** a regulatory construct developed to ensure that there will be sufficient resources available to serve electric demand under all but the most extreme conditions
- **RPS**: Renewable Portfolio Standard, generally a policy requiring a certain portion of electricity generation to come from renewable sources
- **RTO:** Regional Transmission Operator, a single central regional authority to operate transmission systems
- **Scarcity event:** periods of time when electricity demand exceeds available supply
- **SP15:** Energy trading hub in Southern California
- **Spill**: The diversion of water around turbines and through spillways is commonly referred to as "spill" or "spill obligations." Throughout this paper, EGPSC uses the term "spill" to refer to diverting water from turbines to spillways resulting in the loss of hydro-electric generation
- **SRSG:** Southwest Reserve Sharing Group (Southwest sub-regional balancing authority)
- **Sumas:** Gas trading hub near the Washington-Canada border
- **Supply stack:** The portfolio of electricity generators that are used to meet demand
- **TDG:** total dissolved gas, a measurement used in spill
- **Tie line:** Transmission line connecting one region to another
- **USACE**: US Army Corps of Engineers, federal agency in charge of waterways
- **WECC:** Western Electricity Coordinating Council (Western regional balancing authority)

2 Statement of Purpose

This report was prepared by EnergyGPS (EGPSC) for the Public Power Council (PPC). PPC's mission is to preserve and enhance the benefits of the Federal Columbia River Power System for the non-profit, consumer-owned utilities of the Pacific Northwest.

EnergyGPS was formed in 2009 to perform energy analysis for industry professionals. With expertise in public policy, economics, statistics, analytic methods, and computer science, and hands-on experience in energy trading, the EnergyGPS team takes pride in providing sound analysis with serious data acumen.

This report has three objectives. The first is to describe today's PNW electricity markets including how the PNW fits into the broader WECC markets and the evolution of supply and demand. The second is to describe the market's vulnerabilities. These primarily relate to challenges with securing natural gas supply as well as the potential for transmission outages and constraints. The third goal is to provide actual data related to: (a) system conditions during scarcity events to better understand the supply picture under extreme conditions and (b) the impact of implementing more stringent spill rules or breaching the Lower Snake River Dams. The data analysis uses actual data from a wide array of sources including EIA hourly production and carbon emissions data, hydro data from the US Army Corp and USGS, transmission flows from BPA, and pricing data from the InterContinental Exchange.

3 Executive Summary

This paper looks at the impacts of two proposed policy changes to the Pacific Northwest (PNW) hydro system against the backdrop of a rapidly-changing environment. The two proposed policies are 1) increased spill obligations and 2) the removal of the Lower Snake River Dams (LSRD's).

Using actual historical production and market data, EnergyGPS (EGPSC) performed a study to estimate the immediate, short-term impacts of the proposed changes by quantifying the potential hydrological flow changes as MWh, increased carbon emissions, and dollar cost, and applying those results against historical "scarcity event" case studies, which look at how the system maintained reliability during spikes in demand that threatened to exceed supply.

The Western grid and PNW electricity market are rapidly changing as States de-carbonize the electricity grid. Already-enacted policies include incentives for renewable energy, including renewable portfolio standards (RPS's) and carbon pricing; and limitations on thermal energy, including scheduled retirements of coal generation and strict limits on additional natural gas generating resources.

Unfolding changes give even more cause for concern. Electricity demand is anticipated to increase with new policies to transition the sectors of transportation, cooking, and heating to electricity. Natural gas – which would likely provide replacement dispatchable energy in the short-term, has known supply deliverability risks and constraints. And imported energy from neighboring regions cannot be wholly relied upon in the future, as we discuss in depth in this paper.

Strain on the grid is already beginning to show: we show electricity market data that indicates the risk of price spikes and blackouts is the highest it has been since the Western Energy Crisis 20 years ago. Western markets have been experiencing "scarcity events" with greater frequency and magnitude. These types of events create reliability challenges and associated price spikes, and in some unlucky cases, if enough supply cannot be found, can lead to blackouts.

The analysis strongly suggests that costs associated with the proposed policies will be high. With an electric grid that is already prone to scarcity events, removal of the LSRD or implementation of both policies may very well prove to be a tipping point, nudging the PNW system into acute scarcity.

The analysis results show the cost of both policies combined total $790 million per year (based on 2023 prices) and result in increased annual CO2 emissions of 4.2 million metric tons per year.

The analysis of historical case studies is striking: in the past, the majority of gaps in demand have been met by imports from neighboring regions and the hydro system. Imports are anticipating future constraints as our neighbors are experiencing scarcity, too, which leaves the hydro system in a critical grid reliability position when considering the two proposed policies.

The study reveals the scarcity in the markets today and the harm that will come from dramatically reducing hydro supply in the near future. Harms include increased risk of scarcity events, possibly including blackouts, higher carbon emissions, and higher prices for consumers and businesses.

4 Overview

The Western grid and Pacific Northwest (PNW) electricity market are rapidly changing as States across the Western United States de-carbonize the electricity grid and transition to renewable energy. Already-enacted policies include: incentives for adding renewable energy (including renewable portfolio standards (RPS's) and carbon pricing) and limitations on thermal energy (including scheduled retirements of coal generation and strict limits on additional natural gas generating resources).

PNW electricity markets currently sit in a potentially dangerous limbo: replacement infrastructure has not yet caught up with current demand as thermal plants go off-line. Thermal generators, such as coal and natural gas, are being retired or restricted. These thermal generators are being replaced by wind and solar resources.

The differences between renewable and thermal generators are significant for managing the grid: renewable generators are intermittent and production depends on weather conditions, while thermal generators are not fuel-constrained and are "dispatchable", meaning they are able to produce energy on demand.

The trend of retiring dispatchable thermal generation and replacing it with renewable resources has served the intended objective of lowering carbon emissions. However, renewables by themselves are not an adequate replacement for thermal resources when it comes to grid-scale balancing. More infrastructure to balance wind variability – such as pump storage hydro, battery storage, or gas-peaking plants – will be required reliably meet electricity demand. We have also not yet achieved a large enough decrease in peak demand from in demand-side efficiency programs which could curtail demand at critical times of peak use.

The stakes couldn't be higher: there are several State and local policies in development which will result in an even greater reliance on electricity in the future: for transportation (electric vehicles), cooking (bans on natural gas appliances in new buildings), and heating. These policies – some for human health, and some for reducing our climate footprint – are expected to result in significant electricity demand growth in the future.

4.1 The Grid Is Showing Signs of Strain

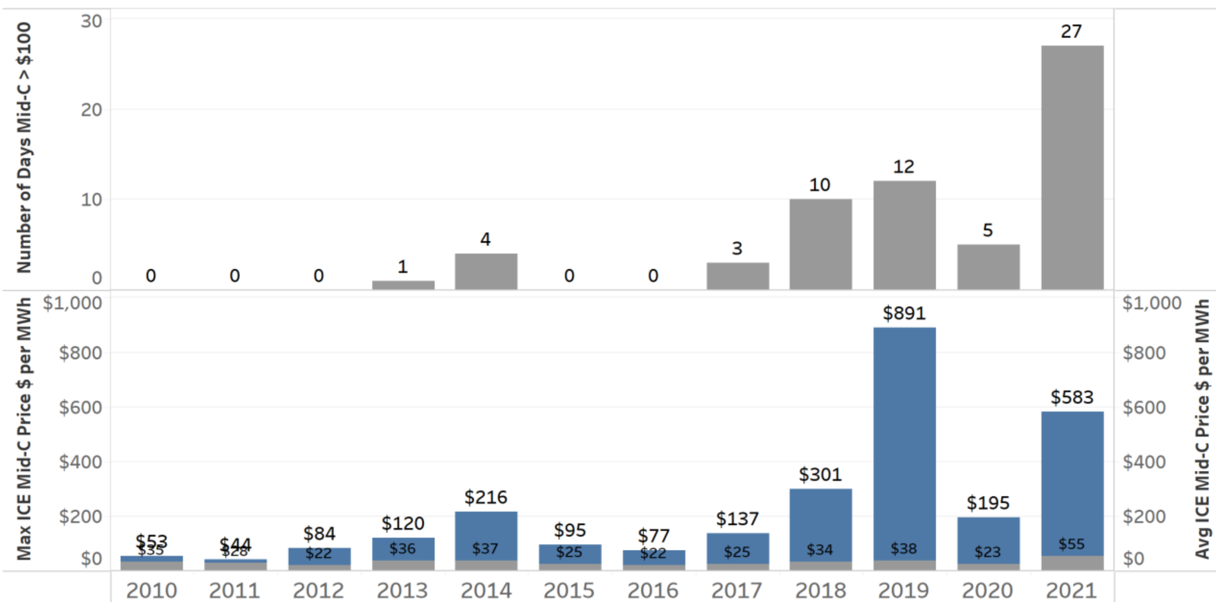
Strain on the grid is beginning to show, due to a triple combination of retiring coal projects, increased variable renewables, and Western-wide constraints on natural gas supply and imports.

To wit, Western markets have been experiencing "scarcity events" more frequently, which are periods of time when the amount of electricity demand comes close to the amount of available supply. During a scarcity event, prices spike as short-term electricity prices rise to levels that are often 10x greater than usual, utilities scramble to secure available supply, and grid operators run through a series of emergency measures prior to instituting rolling blackouts. Only in extreme scarcity events does it turn into a blackout, but when they do the disruption and impact to the public and businesses is large.

Thankfully, scarcity events rarely lead to blackouts. Very often, the difference between a scarcity event and a blackout is driven by a combination of luck and weather. The category of "bad luck" includes natural gas pipeline explosions, wildfires limiting flows on transmission lines, or abnormally high generator outages on a given day. Weather drives demand, and more extreme weather due to climate change is resulting in extreme demand events.

As evidence of scarcity events, one clear indicator is the number of days per year when the electricity market experienced price spikes. The figure below shows the number of days each year when the peak prices traded above $100 per MWh for the Mid-Columbia or “Mid-C” contract traded on the Intercontinental Exchange (ICE)[1] and the maximum price per year.

Figure 1: Days Per Year When Mid-C Price > $100, Max and Avg Annual Mid-C Prices



The figure shows a clear and alarming trend. Focusing on the top pane, prior to 2017 it was rare for Mid-C daily prices to spike above $100 per MWh, with most years never seeing this rise. However, such spikes have become increasingly common since 2017, with as many as 27 in the year 2021.

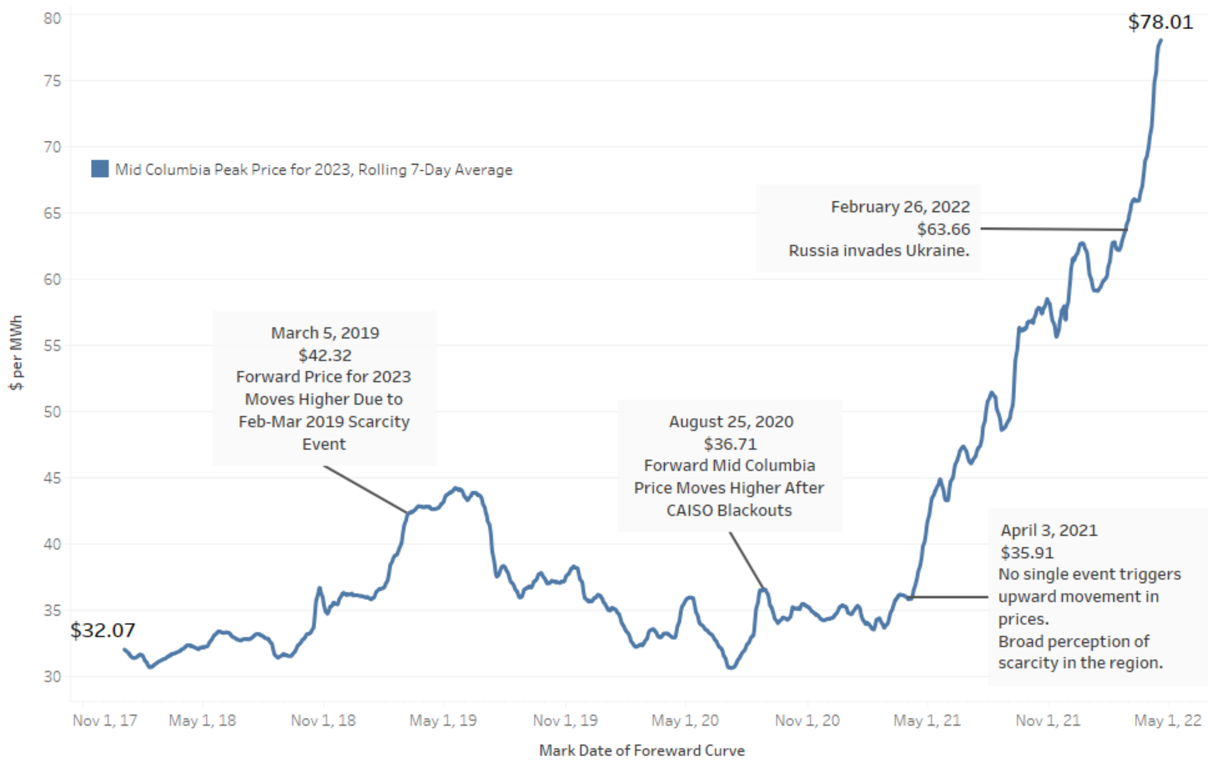
The bottom pane shows the magnitude of the price spikes, showing the maximum price per year in blue. Prices rose above $300 per MWh in 2018, 2019, and 2021. For reference, the bottom pane also shows average Mid-C prices for each year, highlighting how far above normal pricing these spikes are.

While the figure above looks at scarcity and price spikes in the past, it is also possible to gauge expectations of scarcity in the future by looking at “forward” ICE prices for delivery at the Mid-C. The figure below shows the historical trend in futures prices for delivery of electricity at the Mid-C hub during all peak hours[2] in 2023. Futures or forward transactions are for the delivery of electricity at a specific future date and price. Spot or cash market transactions are for immediate delivery.

[1] The Mid-Columbia (Mid-C) hub encompasses five hydro projects: Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapid dams owned by three public utility districts located in Central Washington. The InterContinental Exchange (ICE) is an on-line trading platform which publishes prices for “peak” and “off-peak” products based on actual daily trades.

[2] Peak hours are the hours ending 0700 to 2200 Mondays through Saturdays excluding NERC holidays. The Mid-C forward contract is one of the most liquid electricity contracts traded on the InterContinental Exchange.

Figure 2: Mid-C 2023 Peak Price as Traded on the InterContinental Exchange



Think of this as a "stock ticker" for Mid-C deliveries in 2021. For example, at the beginning of the time series, around November 2017, traders were buying and selling energy to be delivered at Mid-C in 2023 for $32.07. That was the market's expectation in 2017 for what the value of energy at the Mid-C would be in 2023. As recently as April of 2021, the perception of Mid-C value in 2023 was $35.91 per MWh.

However, as we can see from the figure, Mid-C experienced a large number of "cash market"[3] price spikes in 2021, and average cash market prices moved considerably higher that year. In the past twelve months, forward prices have nearly **doubled** because utilities and traders are expecting tight supplies in the future.

The figure is annotated with events that were impacting the short-term markets and showing how some of those events caused traders to re-evaluate their views for deliveries in 2023. For example, there were significant short-term market scarcity events in February and March of 2019. California experienced blackouts in August of 2020, causing a bump in forward prices. The strong cash market price increases which started in April of 2021 further changed people's views of the supply-demand balance moving forward. We can see the 2023 Mid-C prices move up in response to those events as they were happening.

For further discussion, this paper includes Energy GPS Consulting's (EGPSC) detailed analysis of some of these scarcity events. Restricting or removing hydro supply will further worsen the

[3] The term "cash market" in commodity trading usually refers to physical transactions for near-term deliveries, but in electricity trading, "cash market" typically refers to day-ahead trades for delivery the next day.

scarcity challenges faced by the PNW grid, pushing wholesale prices higher which will ultimately flow through to consumers in the form of higher electricity bills.

4.2 PNW Energy Supply: Four "Legs" on the Supply "Stool"

Scarcity events start with high demand, which is most often driven by extreme weather events. The severity of the scarcity event – whether it leads to simple price spikes or more dramatic results like emergency measures or blackouts – relies entirely on the performance of supply resources.

Before describing each of these sources of supply, it is useful to define the "Pacific Northwest market" because there is no single definition of it. Some define it as the states that are part of the Columbia River watershed, which includes Montana, Idaho, Oregon, and Washington. The 1980 Northwest Power Act defines it as the far reaches of the BPA service territory which is slightly larger than the four states listed above. The Northwest Power Pool reliability area covers Oregon, Washington, Montana, Idaho, Utah, Wyoming, Colorado, and parts of California. For the purposes of this paper and the analyses included in this paper, EGPSC defines the Pacific Northwest ("PNW") as Oregon and Washington. Using this definition, EGPSC was able to assemble a high-quality, hourly, dataset for demand and each of the important supply sources.

To understand the reliability of the PNW market, it is necessary to understand the strengths and risks associated with each leg of the supply stool. Below is a brief description of each.

4.2.1 Thermal

This category includes natural gas, coal, and nuclear generation. They generally have reliable access to fuel and can be dispatched to meet increases in demand.

4.2.1.1 Nuclear

The PNW has a single nuclear power plant, the Columbia Generating Station, which is a 1,207MW facility located near Richland, Washington. The Columbia Generating Station has historically performed very well during scarcity events.

4.2.1.2 Coal

Until recently, the PNW coal fleet consisted of two plants (Centralia and Boardman) that totaled almost 1,900MW of supply that historically performed very well during scarcity events. After the retirement of Boardman and one unit of Centralia, the current fleet is 670MW. Outside the PNW, collectively the larger Northwest Power Pool region has retired more than 2,000MW of coal generation since 2019. By 2025 utilities in the region may retire an additional 3,000MW.[4]

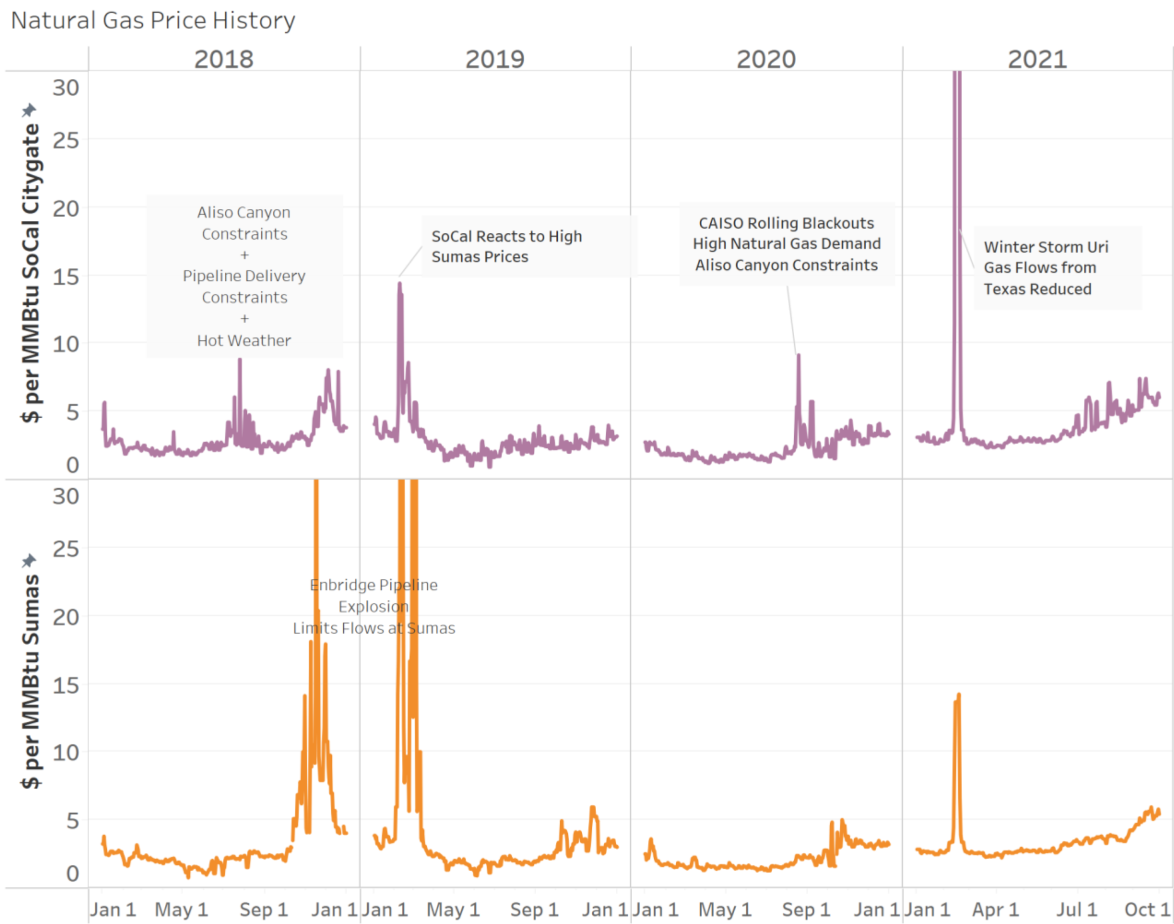
4.2.1.3 Natural Gas

The remaining thermal fleet in Oregon and Washington is comprised of natural gas generation. These units are not at risk for retirement and generally operate consistently and reliably. Oregon has 3,500MW of natural gas capacity while Washington has 2,700MW of natural gas capacity.

[4] Coal units already retired by utilities include Colstrip Units 1 (358MW) and 2 (358MW), Boardman (601MW), Centralia Unit 1 (730MW), and North Valmy Unit 1 (277MW). Coal retirements by 2025 may include Centralia Unit 2 (730MW), North Valmy Unit 2 (289MW), Jim Bridger Unit 1 (608MW), Colstrip Units 2 (608MW) and 4 (778MW).

The natural gas fleet is relatively new – the vast majority of the fleet is under 20 years old. Gas units generally have good availability during scarcity events.

Figure 3: Natural Gas Price History, 2018-2021



The challenges facing the natural gas fleet relate to supply interruptions. There have been many issues with natural gas delivery interruptions to the po3wer sector throughout the United States in the last decade due to everything from cold weather, prioritization of natural gas for heating over electricity, pipeline failures, and even pipeline explosions.

Natural gas pricing data is showing evidence of frailty in its delivery system for the fuel and its competing demands for heating. Unlike the electricity industry, which prides itself on running reliable and redundant systems, the natural gas system lacks such redundancy.

Five pipelines account for 92% of the natural gas delivery capacity into the West (WECC), which approximately 65 million people in the Western states rely on. If any of these pipelines have outages, it impacts all the electricity markets in WECC, as the lost gas generation in one region will impact what happens in other regions.

When supply of natural gas is constrained, the price goes up. The figure on the previous page shows daily natural gas prices from 2018-2021 with annotations describing major issues impacting natural gas deliveries.

As shown in the figure, each of the physical challenges on the natural gas system resulted in higher natural gas prices, and these higher prices effectively ration natural gas deliveries to the electricity generation fleet.

A detailed discussion of natural gas supply constraints is found in the Background section.

4.2.2 Renewable Generation

This category includes wind and solar generators. These are intermittent resources which only generate when the underlying resource (blowing wind or shining sun) is available. To date, PNW renewable generation consists primarily of wind generation. The BPA footprint has approximately 5,000 MW of wind generation, with about 3,000 MW part of the BPA balancing authority and 2,000 MW part of the Avangrid balancing authority.

Solar is currently quite small, BPA has only 138 MW on its system, but this source is expected to rise in the future. This analysis focuses on BPA wind resources because BPA provides quality, hourly production data. There is additional wind located in Pacificorp, Avista, Puget Sound Energy, and Portland General Electric balancing authorities.

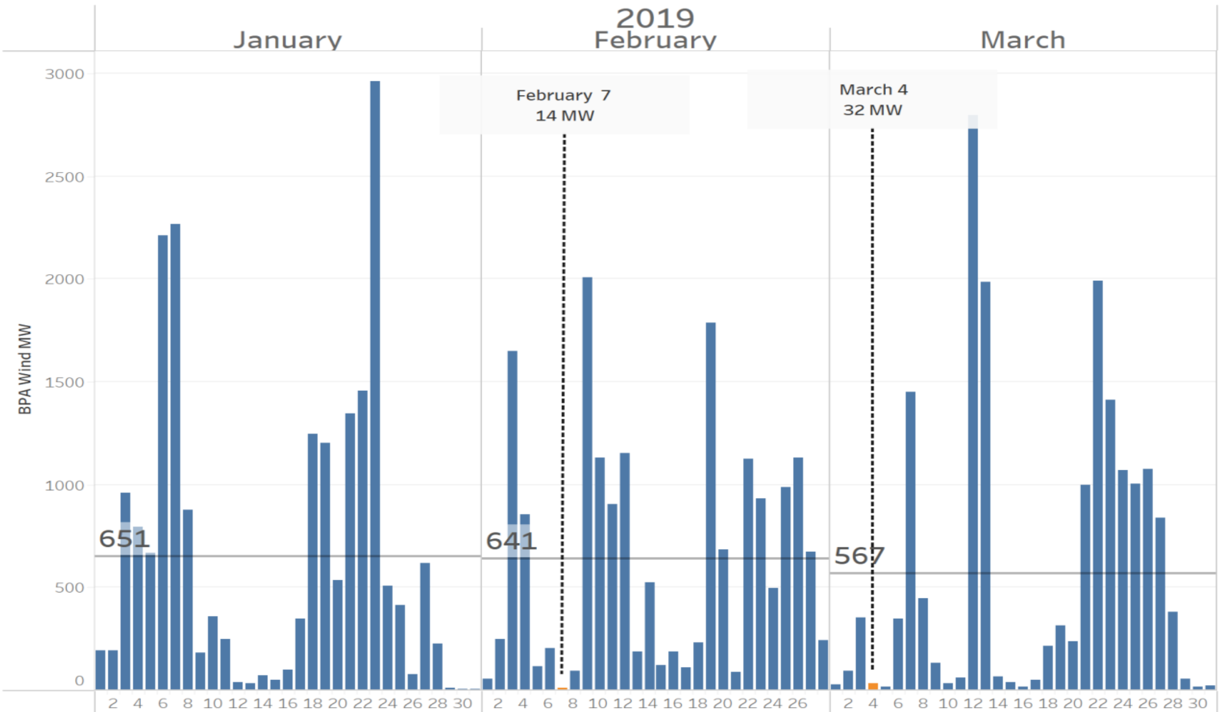
These MW figures are "nameplate capacity," which is the maximum amount the generators can produce at a given time when the weather is cooperating. However, the net amount of energy produced by these generators is typically about one-third of nameplate and the energy is often not available at times when system need is highest.

The vulnerability of renewable generation is its variable output and lack of storage capacity. It only produces when the weather is cooperating and cannot be relied upon for dispatch during limited duration events.

For example, as shown in the figure on the following page, during arguably the biggest scarcity event in the PNW happened during cold weather that hit the region in February and March of 2019, wind production from BPA was anemic.

The figure calls out the two days with the biggest scarcity events – February 7th and March 4th. On these days, as the PNW grid struggled to balance supply and demand, maximum wind generation from BPA was 14 MW on February 7 and 32 MW on March 14. BPA wind production made no effective contribution towards reliability on those two critical days.

Figure 4: BPA Maximum Daily Wind Generation (MW)



4.2.3 Hydroelectricity

This category includes the 60 largest dams in the Columbia River basin and includes projects with and without storage capacity. While supply of hydro varies by the year and the season – based on precipitation and snowmelt – there is a significant amount of storage on the system which allows the hydro fleet to ramp up and down to meet changes in demand and to balance intermittent supplies such as wind and solar.

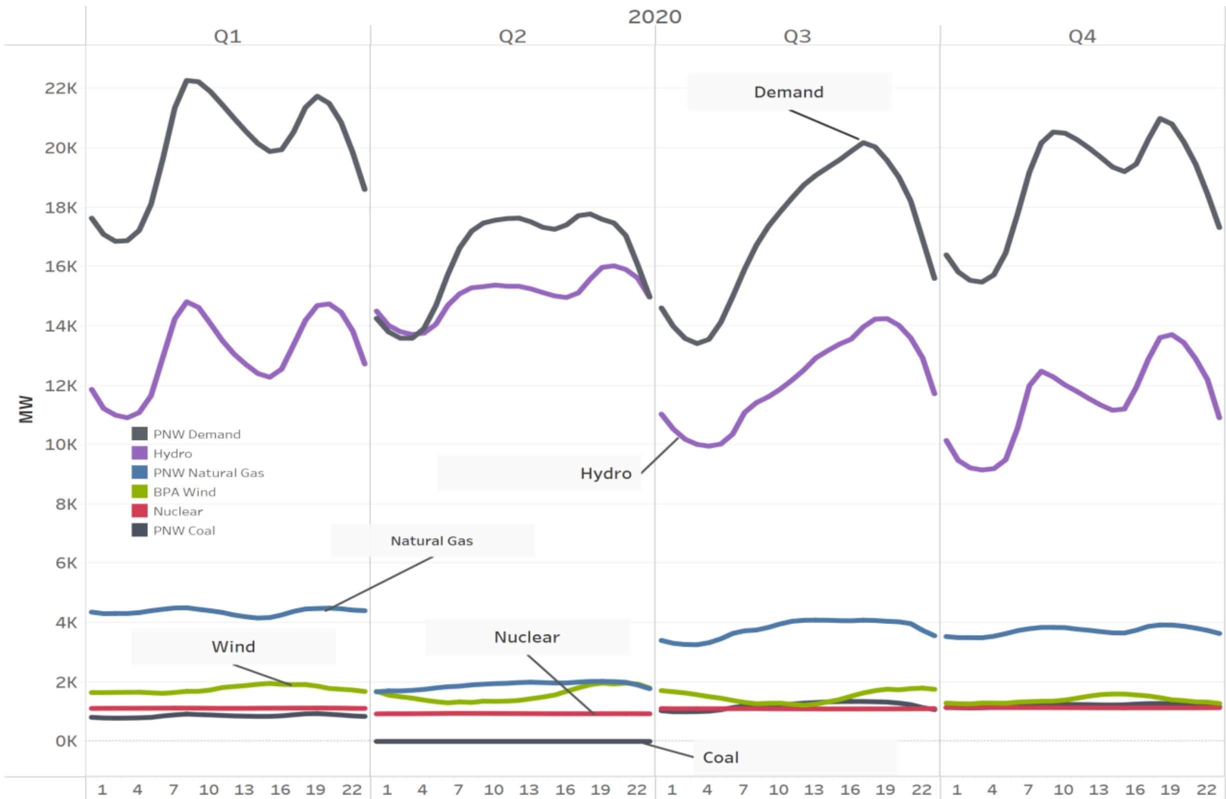
The hydro system plays a pivotal role in the reliability of the PNW electricity grid. It is the largest and most important source of electricity generation in the region. It serves as a carbon-free baseload resource as well as a peaking resource with the ability to dramatically increase output to meet system demand.

The figure on the following page puts the supply sources into context. It shows average hourly production by quarter for 2020.

The central role played by hydro is abundantly clear in this figure. It is, by far, the largest segment of supply and has the flexibility to increase output to meet the hourly changes in demand.

Note that imports do not appear on the figure above. While imports can be an important source of supply during scarcity events, the PNW is typically a net exporter so the import line would be negative if included.

Figure 5: PNW Demand and Supply Sources – By Quarter and Hour for 2020



Of the four legs of the supply stool, hydro provides the highest quality resource: unlike natural gas plants, the fuel (i.e., water running in the river) is on-site, and unlike wind and solar renewables, the hydro system has a combination of seasonal and daily storage capacity which enables it to dispatch electricity during times of high demand even if the natural river flows at that time may be low. It is possible to dramatically increase hydro production for short periods of time (hours to days) when demand is high.

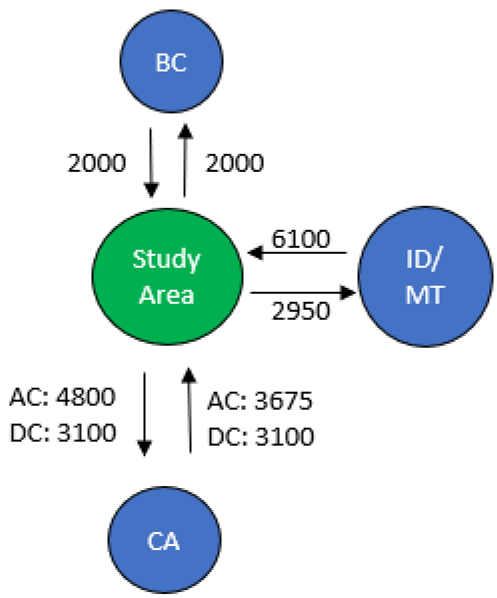
Vulnerabilities to the hydro system include their distance from load centers, which presents transmission risks. Much of those risks have been moderated in the design of the transmission system. Perhaps hydro's most crucial vulnerability is the very subject of this report: proposed policy changes that may alter the quantity and seasonal availability of hydroelectricity due to increased spill or dam removals.

4.2.4 Imports

The PNW energy market operates as part of a larger Western US energy grid body. Transmission is the life blood of Western energy markets, enabling import/export transfers between regions to take advantage of geographically diverse demand and supply. The PNW has robust transmission connections with the North, East, and South. This transmission and exchange of resources provides significant reliability benefits to the PNW: when demand spikes in Oregon and Washington, the region can import energy from the surrounding regions.

The following figure shows the major transmission interconnections and average import/export capability between the PNW and British Columbia to the north, Montana/Idaho to the east, and California to the south. “Study Area” represents the PNW (Oregon and Washington).

Figure 6: Wire Bubble Diagram for PNW Transmission Imports/Exports[5]



Imports have played an important role in meeting demand during times of scarcity, despite the fact that the PNW is a net exporter of electricity. However, availability of imports during times of need is becoming increasingly less reliable:

- Most of the supply that comes via imports is voluntary: it is not contractually controlled by PNW entities and is delivered to the PNW because higher prices make it profitable for the owners of the external generation to make those deliveries.
- Western wildfires represent an increasing transmission reliability risk for the PNW as it changes from a “winter-peaking” region to a “dual-peaking” region. Along with increased temperatures, summers in the PNW are now characterized as wildfire season, and to the south, California has begun focusing on wildfires year-round. These wildfires can impact the major transmission lines into and out of the region, and thus import availability.
- When demand is high in Oregon and Washington, it also tends to be high in BC, Idaho, and Montana. Those regions may not have extra energy to ship to the PNW.
- Supply in British Columbia is closely tied to their internal hydro production. The imports from BC depend on available hydro generation.
- There are a significant number of generating resources which are sold to other regions under long-term contracts. History has shown that even if energy is desperately needed in one region (and prices are extremely high in said region), it can be difficult to re-direct MW because contract provisions limit one’s ability to do so.
- Unlike CAISO with its Resource Adequacy Program, the PNW has no contractual obligation for import supply to the PNW during times of need. The PNW instead relies on voluntary import supply through market pricing.

[5] Source: EGPSC, WECC

4.3 Proposed Policies and Impacts on Hydro Supply

4.3.1 Two Proposed Policy Changes at Discussion

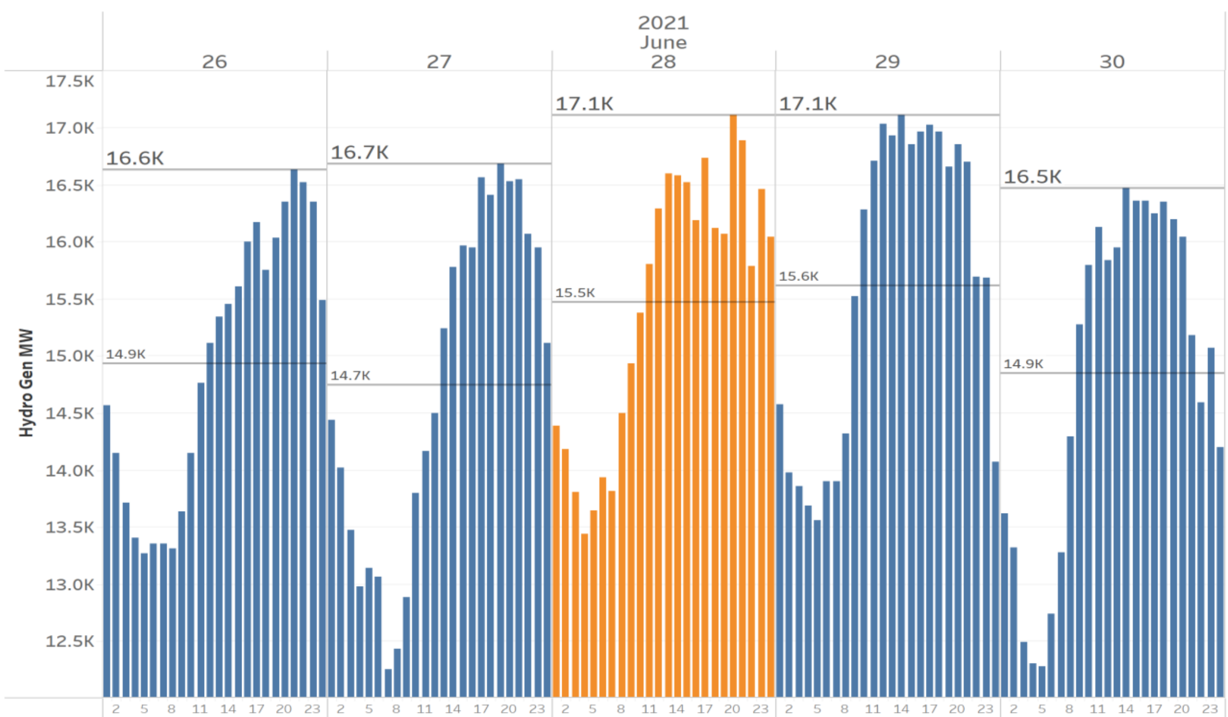
There are two policy proposals that are the subject of this paper and which would reduce the supply of PNW hydro in the future: (1) the lawsuit filed by the State of Oregon in federal court which requests the court to significantly increase the spill obligations on the four Lower Snake River dams (LSRD) and the four lower Columbia dams[6], and (2) the policy proposal to remove the LSRDs.

The incremental changes to mandatory spill requirements sought by the State of Oregon include:

- Add new spill obligations in the months of January to March, reducing the amount of capacity and energy available from these projects during peak winter demand periods.
- Extend spill obligations beyond August 14th of each year, reducing the amount of capacity and energy available from these projects during peak summer demand periods.
- Require projects to operate at minimum operating pool levels, which eliminates the utilization of daily storage at each dam. This causes projects to effectively operate as run-of-river, "flattens" the production profile, and limits the ability to shape water and associated production into the key peak hours.

Naturally, the removal of the LSRDs would eliminate all of the generation from those projects.

Figure 7: Hourly Hydro Production During June 2021 Heat Dome



[6] A description of the requested spill obligations can be found in Appendix A.

4.3.2 Role of Hydro in Times of Scarcity

One need only look at the Case Studies to see how well the hydro system has met PNW demand needs during times of scarcity. The figure on the previous page shows June 26 - 30 when the heat dome had enveloped the PNW. June 28 is highlighted in orange as the day of peak PNW demand.

As the figure shows, at a time when natural flows on the river were declining (commonplace at the end of June), BPA managed to extract 600 MW to 800 MW of higher production to satisfy peak demand. Similar patterns of flexibility are evident during other scarcity events, as discussed in Case Studies.

4.4 Study Purpose and Results

The purpose of this analysis was to estimate the energy and capacity impacts of the proposed policies to improve salmon recovery, estimate the increased carbon emissions, estimate the direct, short-term, financial costs stemming from those policies, and provide real-world data and examples of the potential reliability implications.

4.4.1 Estimated Impacts of Proposed Policies: Resources, Costs, and Emissions

EGPSC completed an analysis which estimated the lost energy and capacity associated with each of these policy changes in isolation plus the combined impact. The results of this analysis are summarized in the table on the following page.

The analysis strongly suggests that costs associated with the proposed policies will be high. With an electric grid that is already prone to scarcity events, removal of the LSRD or implementation of both policies may very well prove to a tipping point, nudging the PNW system into acute scarcity.

The cost of both policies combined to BPA, its customers, and the region total $790 million per year based on 2023 prices. This is an illustrative, single-year value based on actual market prices for 2023. The region would lose 2,556 MW of winter capacity and 1,809 MW of summer capacity. These resources would not be available to meet demand when most needed on extreme days. Importantly, the lost energy would almost certainly come from natural gas generators for the foreseeable future, resulting in increases annual emissions of 4.2 million metric tons of CO2. To put this into perspective, replacing energy resulting from increased spill rules and removing the Lower Snake River Dams would account for 8% of Washington’s 2030 target emissions and 13% of Washington’s 2040 target emissions.

Table 1: One-Year Impacts on Lost Resources, Costs, and Carbon Emissions

	Units	One Year 2023 Cost Increased Spill	One Year 2023 Cost LSRD Removal	One Year 2023 Cost LSRD Spill + LSRD
Energy Value				
ICE Price All Hours	$/MWh	$66.49	$66.49	$66.49
Volume-Weighted Value	$/MWh	$58.80	$60.90	$61.21
Avg Lost Energy	MW	435	919	1133
Replacement MWh	MWh	3,808,066	8,048,174	9,923,614
Replacement Energy $	$	**$223,899,194**	**$490,160,831**	**$607,414,401**
Capacity Value				
Lost Winter Capacity	MW	515	2,284	2,556
Lost Summer Capacity	MW	930	1,644	1,809
Replacement Capacity	MW	723	1964	2183
Capacity Price	$/kW-Mo	$7.00	$7.00	$7.00
Replacement Capacity $	$	**$60,690,000**	**$164,976,000**	**$183,330,000**
2023 Replacment Cost	$	**$284,589,194**	**$655,136,831**	**$790,744,401**
Increased CO2 Emissions	Tons	**1,629,852**	**3,444,618**	**4,247,307**

Replacement Capacity Estimates Max Lost Winter and Max Lost Summer Capacity

ICE Price All Hours Based on Forward Market Prices Published by the InterContinental Exchange (ICE)

Capacity Price Based on Recent WECC Capacity Price Quotes from Brokers

Carbon emissions assume 0.428 tons of carbon per MWh of electricity

4.4.2 Case Studies: PNW Has Come Close to Trouble in Recent Scarcity Events

In the Case Studies section, EGPSC explains what “scarcity events” are (periods of time when electricity demand approaches available supply), discusses the supply sources available to moderate scarcity events, evaluates how PNW demand was met during three separate scarcity event case studies, analyzes what would have happened in each scarcity event if the proposed policy changes to hydro had been in place, and provide a discussion of notable national scarcity events blackouts in California, and challenges faced by PJM and ERCOT.

The first three case studies illustrate exactly how the PNW region has balanced supply and demand in the past to avoid blackouts: by using all available in-region thermal resources, flexible in-region hydro resources, and imports from the surrounding regions.

In the fourth, we discuss the PNW role in the CAISO Heat Wave Blackouts of August 2020, and compare the PNW to two major national scarcity events: the January 2014 PJM Polar Vortex, and the February 2021 Texas Winter Storm Uri.

The results of the case studies are summarized in the table on the following page. The vulnerabilities of each leg of the supply stack reveal themselves in this summary table:

- **Natural Gas Generation** is vulnerable to supply constraints and delivery risks, and in the winter, heating demand takes priority over electricity generation. For example, in March of 2019 the natural gas fleet generated only 3,400MW out of maximum capacity of 5,900MW.

Table 2: Summary of Scarcity Event Case Study Analysis

	Case 1 Feb 2019	Case 2 Mar 2019	Case 3 Jun 2021	PJM Polar Vortex Jan 2014	CAISO Blackouts Aug 2020	Texas Blackouts Feb 2021
Trigger	Cold snap	Cold snap	Heat dome	Cold snap	Heat	Winter storm Uri
Mid-C Price	$138	$890	$334	n/a	$51	n/a
PNW Demand	29,500 MW	27,300 MW	28,400 MW	n/a	24,700 MW	n/a
Baseload (Coal and Nuclear)	Performed well	Performed well	Still some outages	Generator outages	Nuclear performed well.	Under-performed
Natural Gas	4,600 MW Limited: supply competed with heating needs	3,400 MW Limited: supply competed with heating needs	4,200 MW Limited: generator outages	Generator outages and supply issues	Under-performed	Failures throughout the natural gas supply and generation systems
Imports	+6,000 MW. Record import level.	+4,500 MW.	+1,600 MW.	Under-delivered	PNW Exported Under-delivered: transmission de-rated	n/a: few interconnections to Texas grid
Renewables	Extreme low wind event	Extreme low wind event	Low wind event	n/a	Under-performed	Underperformed
Hydro Max	16,700 MW	15,600 MW	17,100 MW	n/a	17,082	n/a
Hydro Daily Flex	7,200 MW	5,900 MW	3,200 MW	n/a	6,600 MW	n/a
Proposed Policy: Lost Hydro Capacity	-1,700 MW (combined)	-1,778 MW (combined)	-992 MW (combined)	n/a	-1,944 MW (combined)	n/a

- **Imports** into the PNW region varied greatly from one scarcity event to the next. The record-setting level of imports in February 2019 likely kept the lights on in the PNW. Imports were only 1,600MW during the heat dome event in June 2021 with little help coming from British Columbia or the East side. It required prices to rise above $300 per MWh to attract imports from California.
- **Renewables** in the BPA service territory performed extremely poorly during the winter of 2019 and poorly during the heat dome in 2021. Renewables simply can't be counted on to help during extreme events.
- **Baseload Resources** performed well. With coal retirements in the PNW and in the broader region, this portion of the supply portfolio will continue to shrink which will impact in-region resources and also available imports.

In many ways, it is often luck which determines which challenges hit the grid during any given scarcity event. It is easy to see how the February 2019 scarcity event could have been much worse with the following adjustments:

-1,300 MW of baseload coal generation due to Centralia and Boardman retirement
-1,200 MW of natural gas generation if supply constraints existed as in March 2019
-1,700 MW of lost hydro production due to policy changes
-4,200 MW less supply compared to February 2019

The results of the case studies are stark: the PNW region, and indeed the Western region as a whole, relies heavily on the flexibility of the hydro system during extreme conditions. It has come to not only the PNW's rescue, but also neighboring regions, during times of extreme need, and may be a differentiating factor that has prevented the PNW from having blackouts like other major nationally-reported blackouts discussed in the fourth case study section.

4.4.3 Recommendations

While this is not policy paper which delineates fixes that would be helpful to mitigate the issues raised, in this paper there were several key ideas discussed that are worth revisiting briefly:

- **Understand the Risks Facing the PNW**: a region-wide state of scarcity, coal retirements, wildfires, natural gas delivery risks, climate change weather events, and growing demand.
- **Realize the Electricity System Implications of the Proposed Policy Changes**: as summarized in our analysis, spill policies can be designed with flexibility during scarcity events to prevent blackouts, but once gone, the LSRD dams will not come back. Both policies should be considered in light of each other.
- **Prioritize the Western Resource Adequacy Program**: The purpose of a Resource Adequacy Program is to develop a common way to "do the math" of total resource capacity and ensure that utilities have procured sufficient resources to meet demand plus a planning reserve margin.
- **Invest in Major Transmission Infrastructure:** Thoughtful coordination between resource planning and transmission needs will be required to achieve lofty RPS targets.
- **Protect the Grid with Wildfire Preparedness:** An area that has to be advanced is the interplay between wildfire risk, resulting transmission outages, impacts on reliability, and the generation resource decisions that should be informed by all of this analysis.
- **Plan for Natural Gas Infrastructure:** The most notable blackouts or near-blackouts in the last twenty years involved failures in the natural gas generation fleet.
- **Create an RTO Market:** As recommended in FERC Order 2000, an RTO allows for easier integration of renewables, better coordination of the transmission grid, and more efficiently dispatches and moves electricity across a broad geographic region.
- **Define the Opportunities and Limitations of Battery Storage:** Removing dispatchable resources and replacing these resources with batteries means the planners need a better idea of how many batteries are required to achieve the same level of reliability.

5 Background

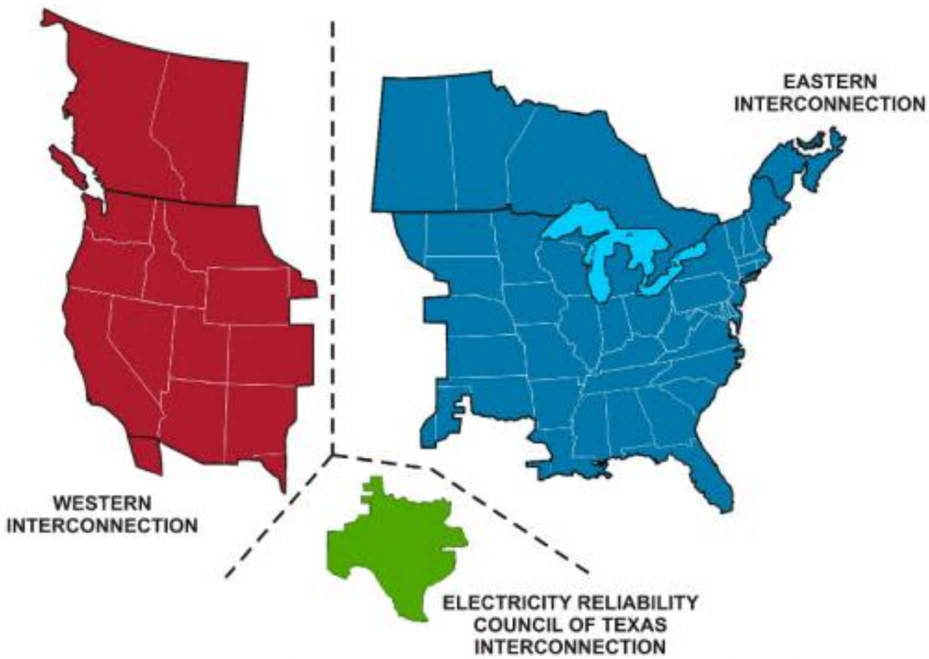
The objective of this section is to provide background context on today's PNW electricity markets including how the PNW fits into the broader WECC markets and the evolution of supply and demand. A solid understanding of these concepts will enhance understanding of the study and analysis in the following sections.

5.1 Introduction to Western Electricity Markets

5.1.1 WECC

The U.S. electrical system is made up of three major interconnections with limited transfer between each - the Eastern Interconnect (EI), the Electrical Reliability Council of Texas (ERCOT), and the Western Interconnect (WI). Roughly speaking, the EI covers all of the states to the East of the Rockies and the WI covers the states to the West of the Rockies. ERCOT covers most of the State of Texas.

Figure 8: Map of US Electricity Grids [7]



Reliability within the WI is overseen by the Western Electrical Coordinating Council (WECC), as established by the North American Electric Reliability Corporation (NERC). The WECC covers 14 states as well the Canadian Providences of British Columbia and Alberta and the northern part of Baja Mexico. The WECC is NERC's largest geographic Reliability Entity (RE) with over 1.8 million square miles of area serving nearly 85 million people[8].

The WECC is often broken down into five subregions for purposes of understanding reliability: Northwest Power Pool (NWPP), California and Mexico (CA/MX), the Southwest Reserve Sharing

[7] Source: https://www.industrytap.com/wp-content/uploads/2016/05/North-American-Electric-System.jpg
[8] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

Group (SRSG), Alberta (AB), and British Columbia (BC).[9] The rationale for grouping by the NERC is due to similar operating practices and demand patterns.[10]

Figure 9: Reliability Regions within WECC [11]

The BC subregion has a peak load of approximately 11,000 MW and has nearly 18,000 MW of generating resources, of which over 15,000 MW is hydro. BC is electrically connected to the NWPP as well as AB.

- AB has a peak load of just over 12,000 MW and has approximately 19,000 MW of generating capacity, primarily comprised of coal and natural gas. AB has pledged to be 30% renewable by 2030[12] and is planning to retire its entire coal fleet by 2023[13]. AB is electrically connected to BC and the NWPP.
- The CA/MX NERC subregion has over 55,000 MW of peak load and approximately 81,000 MW of generating resources with significant amounts from natural gas, solar, hydro, and wind. For reliability purposes, CA/MX counts on over 4,000 MW of firm imports from the NWPP and SRSG.
- The SRSG has nearly 26,000 MW of peak load and approximately 38,000 MW of generating resources comprised mostly of natural gas, coal, and nuclear generating units.
- The NWPP NERC reliability area covers Oregon, Washington, Montana, Idaho, Utah, Wyoming, and Colorado, as well as parts of California (e.g., the Balancing Area of Northern California). The NWPP has approximately 64,000 MW of peak load and nearly 110,000 MW of generating resources, which are primarily comprised of hydro, natural gas, and coal. As with other regions, a significant amount of coal generation has been, or is planned to be, retired.

The WECC generating resources are depicted in the two figures below. Note for both graphs, NWPP includes former subregion of Rocky Mountain Reserve Group.

[9] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf
[10] Note: NWPP includes the former subregion of Rocky Mountain Reserve Group, while for the purposes of this report the PNW includes only Washington and Oregon.
[11] Source: EGPS
[12] https://www.alberta.ca/renewable-energy-legislation-and-reporting.aspx
[13] https://www.jwnenergy.com/article/2020/12/7/alberta-set-to-retire-coal-power-by-2023-ahead-of-/

Figure 10: WECC Generating Capacity by Fuel Type and NERC Region

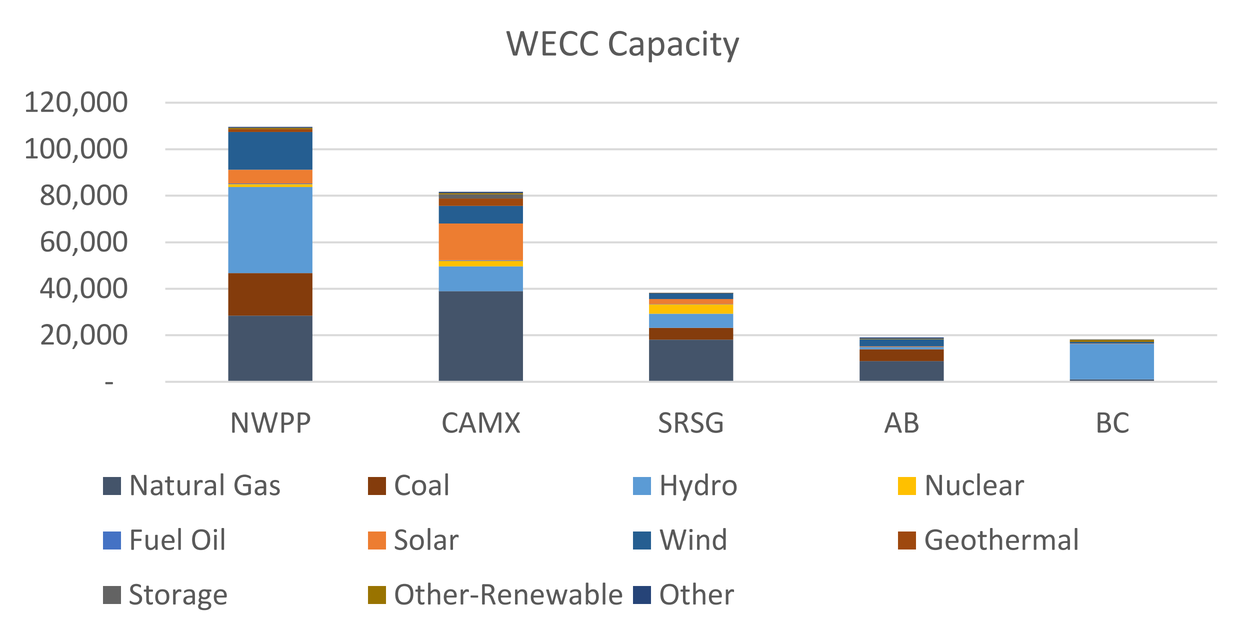


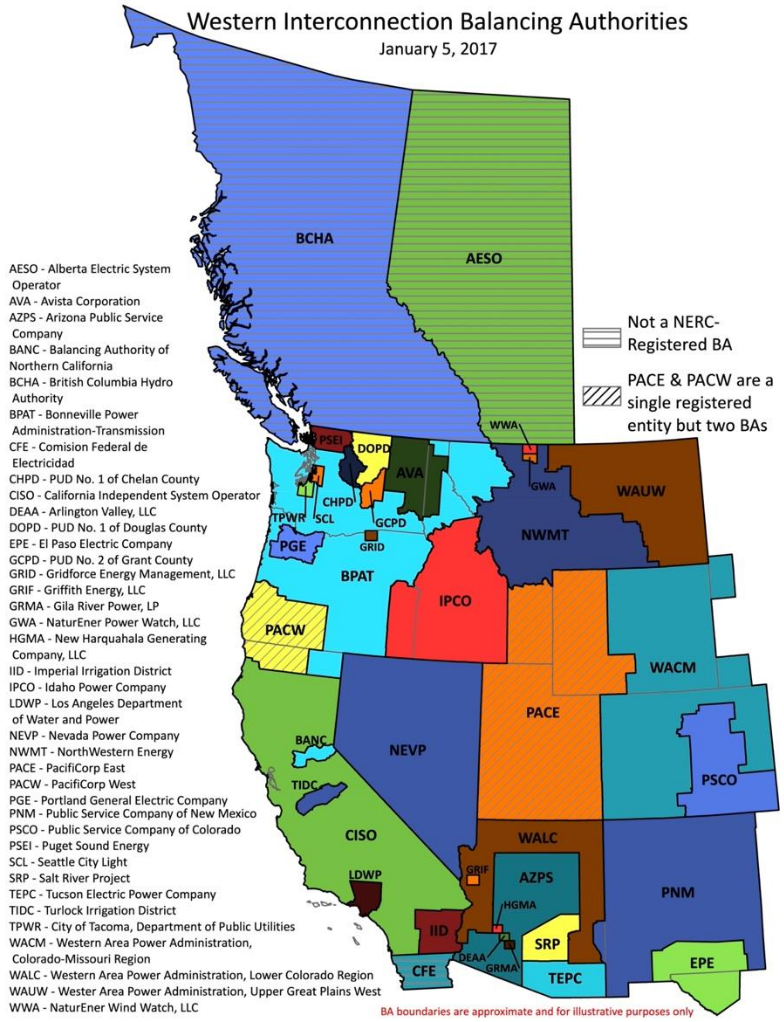
Figure 11: WECC Generating Capacity by Fuel Type and NERC Subregion [14]

Fuel	NWPP	CA/MX	SRSG	AB	BC
Natural Gas	28,381	38,948	18,127	8,940	1,034
Coal	18,422	12	5,059	5,125	-
Hydro	36,956	10,711	6,058	933	15,363
Nuclear	1,172	2,240	4,003	-	-
Fuel Oil	307	400	165	-	-
Solar	5,936	15,814	2,219	247	72
Wind	16,290	7,522	2,376	3,028	635
Geothermal	1,184	3,134	19	-	107
Storage	19	1,784	71	-	-
Other-Renewable	468	626	22	327	920
Other	438	520	9	453	45

Daily operation within the WECC is the responsibility of 38 Balancing Authorities (BA). Part of the daily operation requirements for a BA is to ensure load and generation are balanced on a fine temporal scale. This is accomplished by perfectly balancing load and generation within the balancing authority footprint, on a second-to-second basis such that system frequency is maintained at 60 hertz.

[14] Source: Data aggregated by EGPS from numerous sources including EIA, US Army Corp of Engineers, and various other sources.

Figure 12: Map of WECC Balancing Authorities



The California Independent System Operator (CAISO) maintains the balancing for much of California as well as the Western Energy Imbalance Market (EIM). Within the SRSG, the BA's are WAPA Lower Colorado, Arizona Public Service, Salt River Project, Tuscon Electric Power, Public Service of New Mexico, and El Paso Electric. Within the NWPP Rocky Mountain region (as defined by NERC), the BA's include Public Service of Colorado, WAPA Rocky Mountains, and Pacificorp East. Within the NWPP region outside of the Rocky Mountains, the BA's include WAPA Upper West, NW Montana, Idaho Power, Pacificorp West, Bonneville Power, Avista, Portland General Electric, Seattle City Light, Tacoma Power, Puget Sound Energy, and various Public Utility Districts (PUD') including Grant County, Douglas County, and Chelan County.

5.1.2 The Pacific Northwest Market

There is no single definition of the "Pacific Northwest market". Some define it as the states that are part of the Columbia River watershed, which includes Montana, Idaho, Oregon, and Washington.

The 1980 Northwest Power Act defines it as the far reaches of the BPA service territory which is slightly larger than the four states listed above.

The NWPP reliability area covers Oregon, Washington, Montana, Idaho, Utah, Wyoming, and Colorado, as well as parts of California. Still others include non-California portions of the NWPP which could include northern Nevada and Utah.

However, for the purposes of this study, EGPSC defines the Pacific Northwest (or "PNW") as Oregon and Washington, and has isolated state-level data from regional datasets as discussed in more detail in Study Methodology.

5.2 PNW Supply Stack

The "supply stack" is the portfolio of electricity generators that are used to meet demand, and the PNW has a diverse portfolio of generation resources, discussed in turn below.

5.2.1 Thermal

An important component of the PNW supply stack is the thermal "fleet," which is the aggregate supply of nuclear, coal, and natural gas generators.

Figure 13 on the following page shows load (demand) and each of these thermal resources. We include imported energy with this data as the imported "resource" is also central to the supply-demand balance in the region.

The major components of the supply-demand balance outside of hydro are displayed above. The system has a limited number of moving parts:

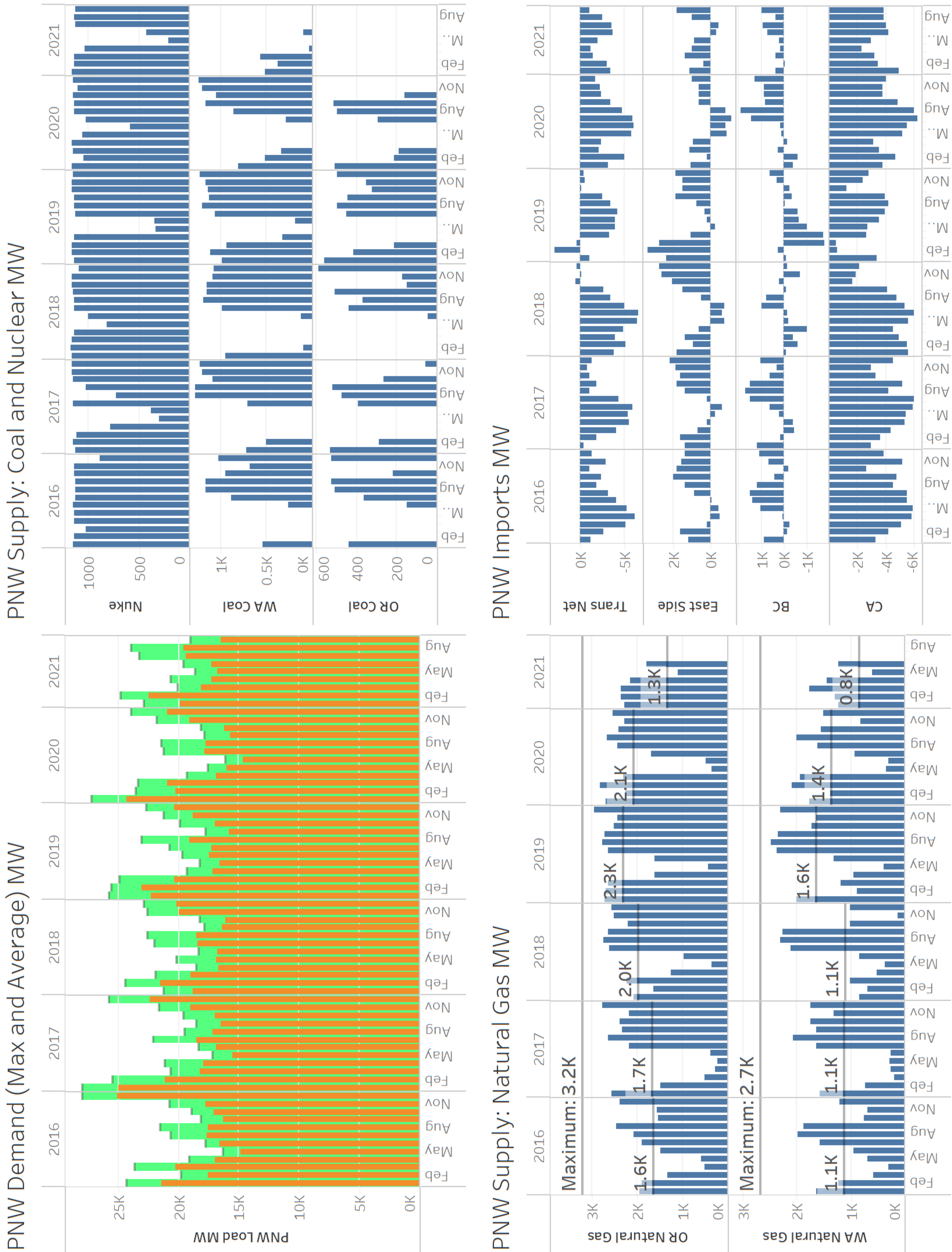
- Demand is depicted in the upper left, showing maximum hourly demand (gray) and average demand (orange) by month. The region is winter-peaking, with the highest demand of 28,000 MW occurring in December of 2016.
- Coal and nuclear units are depicted in the upper right. The nuclear unit is the Columbia Generating Station with a capacity of just around 1,200 MW. When running, it operates at a high "capacity factor" (the percentage of time the generator is available to produce electricity upon demand). Washington coal is Centralia, and Oregon coal is Boardman. Note that one unit at Centralia and the entire Boardman facility were retired at the end of 2020. As of 2021, there are about 600 MW of coal left on the system.
- The bottom left shows natural gas plants in Oregon and Washington. Oregon has 3,200 MW of installed capacity while Washington has 2,700 MW. The capacity factor of natural gas varies greatly by month and by year.
- The bottom right shows imports and exports. Positive numbers reflect imports into the region while negative numbers reflect exports. The top pane shows the net value: the PNW is a net exporter in almost all months and all years. The region generally imports from the lines to the east and from BC, however there are notable periods where the flows reverse, such as early in 2019. The PNW region is a large net exporter to California. The most important supply resource in imports/exports is hydro generation which will be discussed in the next section.

The largest changes to the thermal supply stack in the last 5 years have been the loss of the Centralia and Boardman coal units. Those retirements are the first of many to come.

Figure 14 shows the cumulative capacity of coal plants that are slated to retire – some over the next several years and others in the 2030s. This is expected to reach nearly 16,000 MW of capacity by 2040.

The remaining Centralia unit is scheduled to retire in 2025. Of note, are the Jim Bridger and Colstrip units which provide important supply to utilities within the PNW footprint. Jim Bridger is a 2,400 MW coal plant operated by Pacificorp located in Wyoming.

Figure 13: PNW Load and Thermal Supply by Resource (MW), 2016-2021

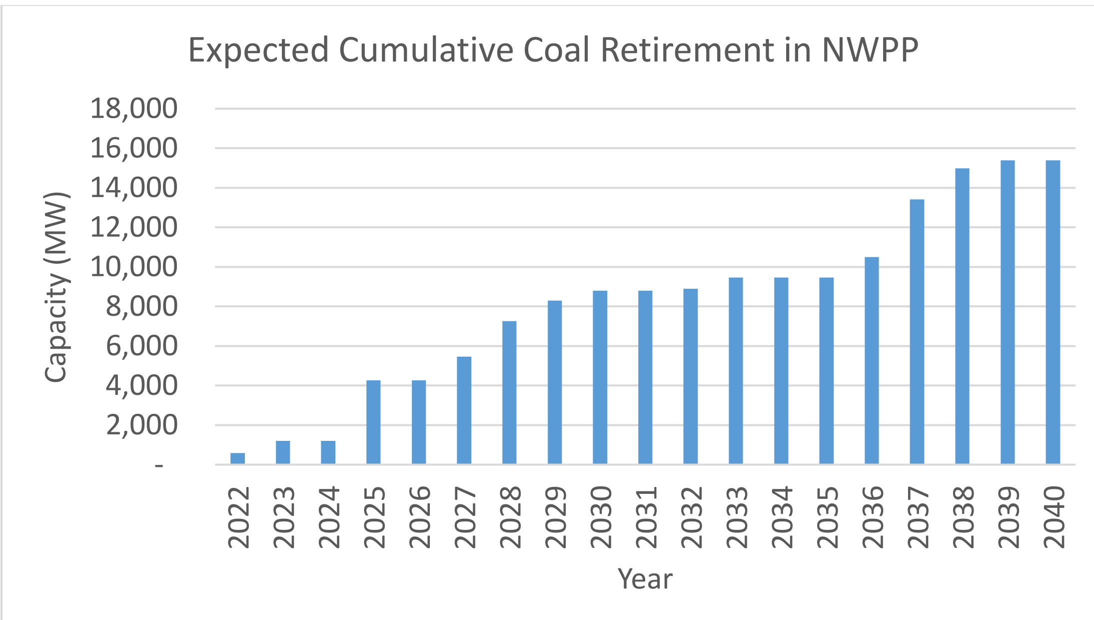


The continued operation of Jim Bridger has been the subject of litigation between the EPA and the State of Wyoming. Two of the four units are slated to be converted to natural gas with the fate of the other two units still unsettled.

Colstrip is a 2,100 MW coal plant located in in Montana. Two units of Colstrip retired at the end of 2019 (680MW), which has reduced imports into the PNW from the east. Utilities in Oregon and Washington have plans to cease take energy from the remaining Colstrip units (1,480 MW) by 2027.

While these units are not within the "PNW" market region as defined by EGPSC, they are part of the system that provides the East side imports. The available energy from Montana (Colstrip), Wyoming (Bridger), and northern Nevada (Valmy) will surely put downward pressure on imports from the East side in years to come.

Figure 14: Expected Coal Retirements in the NWPP [15]



5.2.2 Hydro: The Unique Role of BPA in PNW Electricity Markets

The hydro system is, by far, the largest and most important generation resource in the region, and it is run by the Bonneville Power Administration (BPA), a federal agency. BPA serves a unique role within the PNW electricity system: it sells the output of federally-owned and federally-managed dams located in four Northwest states: Oregon, Washington, Idaho, and Montana. BPA also owns and manages the transmission grid which brings that hydro electricity to customers throughout the region.

In the figure on the following page, the transmission lines (yellow) serve as a large gathering system to bring hydro generators (orange points) located along the rivers (blue) to the load

[15] Source: EIA, NWPP, EGPSC

centers, the largest of which are west of the Cascades. Note how robust the transmission system is along the main stem of the Columbia in Washington and Oregon.

Transmission infrastructure has been built and maintained over decades to accommodate the dam system. Replacing supply from the BPA hydro system with renewables will require more than building new renewable generators and storage resources: it will also require significant transmission investments.

The role of transmission and transmission risk is discussed later in this report, but it is worth mentioning here that the BPA hydro and transmission systems were built to operate together. If output from dams is replaced with renewable resources located elsewhere (e.g., solar in southeastern Oregon or wind in Montana) the transmission system will have to be extended to reach and integrate these resources. It takes a long time and a lot of funding to develop, permit, build, and energize new long-distance transmission lines.

Figure 15: Map of BPA Dams and Transmission System [16]

Based on recent conversations with renewable developers interconnecting to BPA, it may take up to 10 years for new projects entering the BPA queue to receive approvals, await transmission upgrades to be completed, and be built and energized. Recall that it took the New Deal-era Rural Electrification Act of 1936 to bring electricity out to America's rural areas in the first place, a massive federal investment. Recent attempts to expand transmission lines have often face

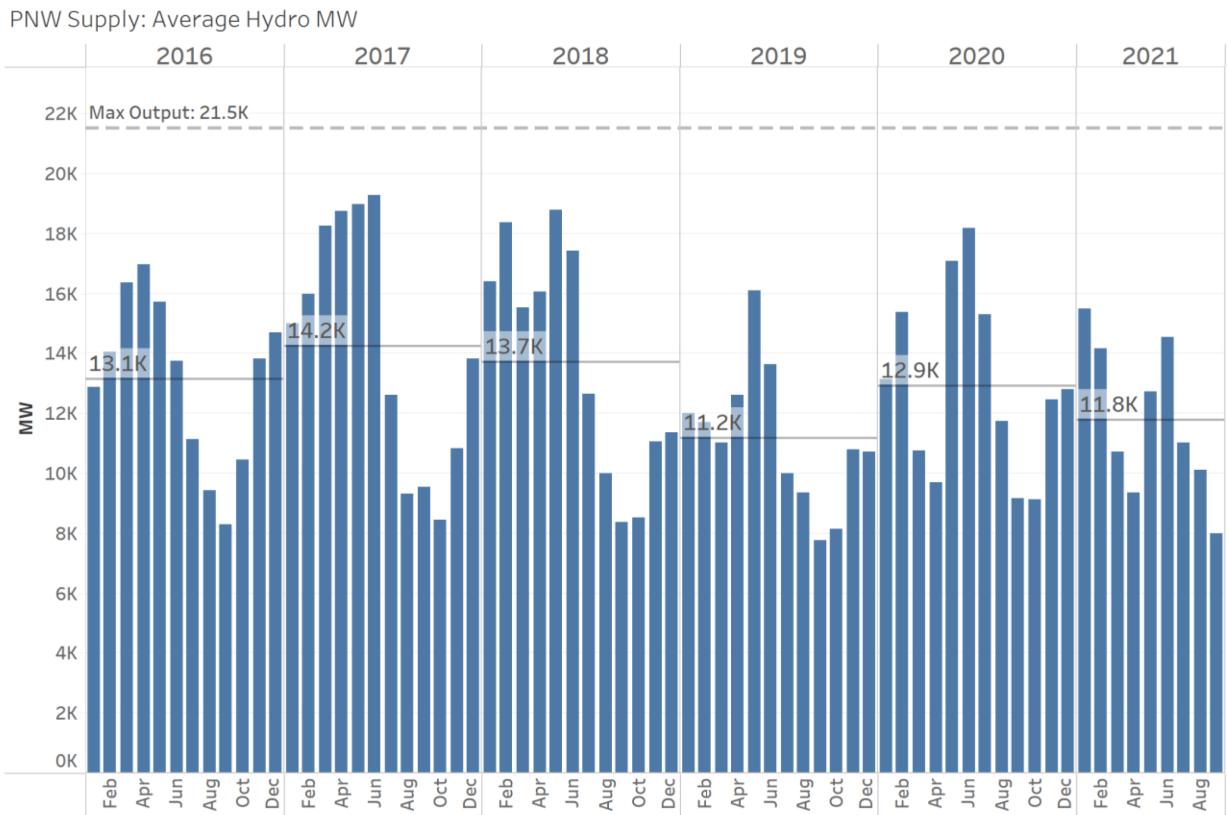
[16] Source: https://www.oregon.gov/energy/Data-and-Reports/Documents/2020-BER-Energy-101.pdf

organized local resistance which complicate permitting and construction timelines, such as the Stop B2H Coalition for Idaho Power's proposed Boardman-to-Hemingway line[17] and localized opposition to the TPUD Tillamook-Oceanside line.[18]

Figure 16 shows the EGPSC hydro data series on a monthly basis from 2016 through 2021. This covers 60 dams with 92% of the installed hydro capacity in the Columbia River system plus other dams in Oregon and Washington.

The nameplate capacity of these dams is just above 30,000 MW. However, the maximum output from these dams has been 21,500 MW from 2016-2021. The gap between nameplate and maximum output has to do with maintenance, outages, timing of flows, spill, and other constraints on the dams. In any given year, the average production on this 60 dam system ranges from 11,200 MW to 14,200 MW. The hydro system dwarfs all of the other resources in the region.

Figure 16: PNW Hydro Production (MW), 2016-2021



Hydro generation provides low-cost, carbon-free energy for both baseload energy and peak capacity. Day in and day out, all hours of the day, all year round, the dams generate the majority of the electricity that supplies the PNW grid – this is the "baseload" portion of the output, and this is what most people think of when the picture the hydro system. Equally important are the "peaking" capabilities of the dams, which is the ability to ramp up when needed.

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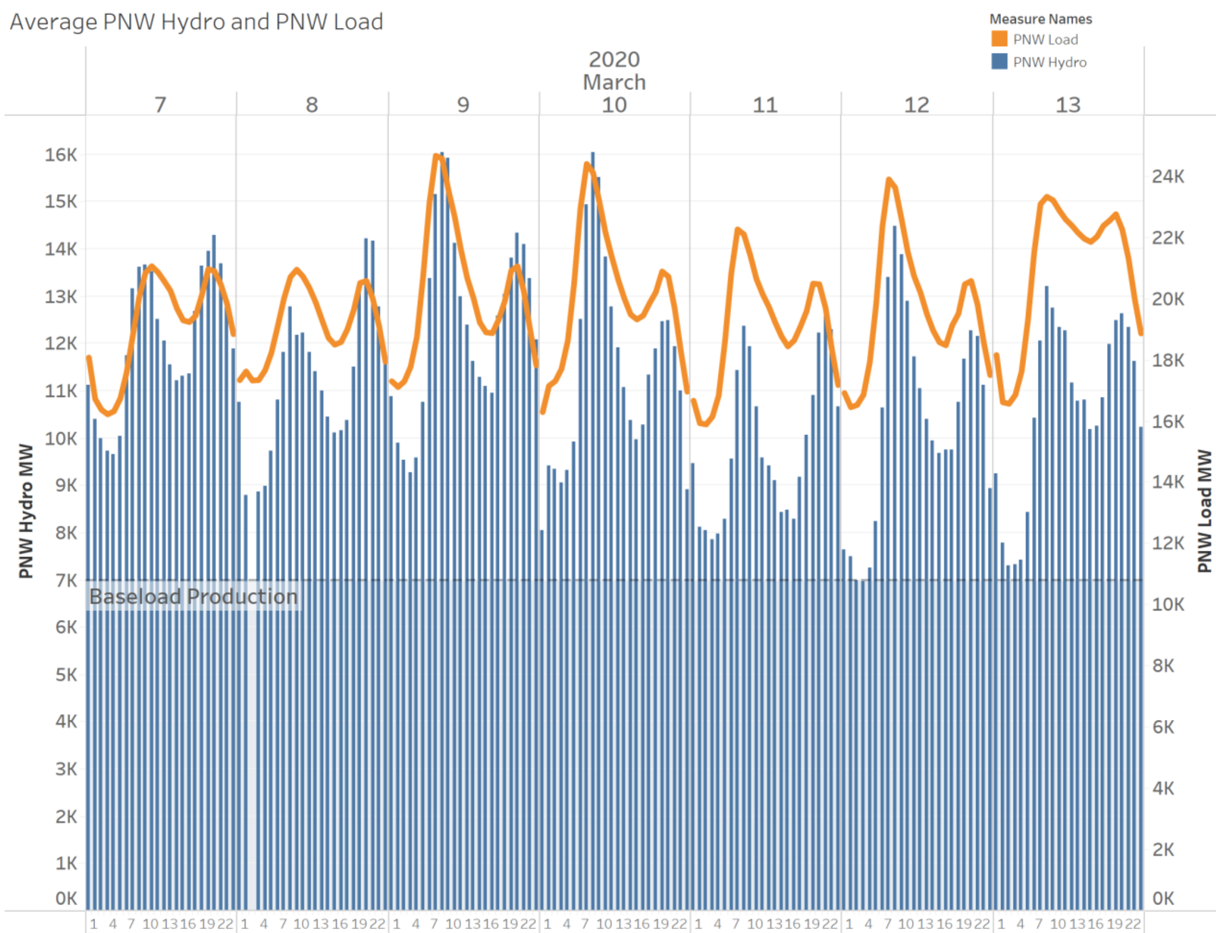
17 http://stopb2h.org

18 https://www.columbian.com/news/2018/jan/02/plan-for-transmission-line-between-tillamook-and-oceanside-draws-opposition/

ENERGYGPS CONSULTING LLC

Figure 17, which is from a week in March of 2020, shows hourly Oregon and Washington demand along with output from the hydro system. Blue bars depict hydro production and the orange line shows hourly demand. Note that the hydro system is dispatched to meet demand. The reference line at 7,000 MW of hydro output distinguishes the “baseload” production from the “peaker” production during this time.

Figure 17: Hourly Demand and Hydro Production, March 2020

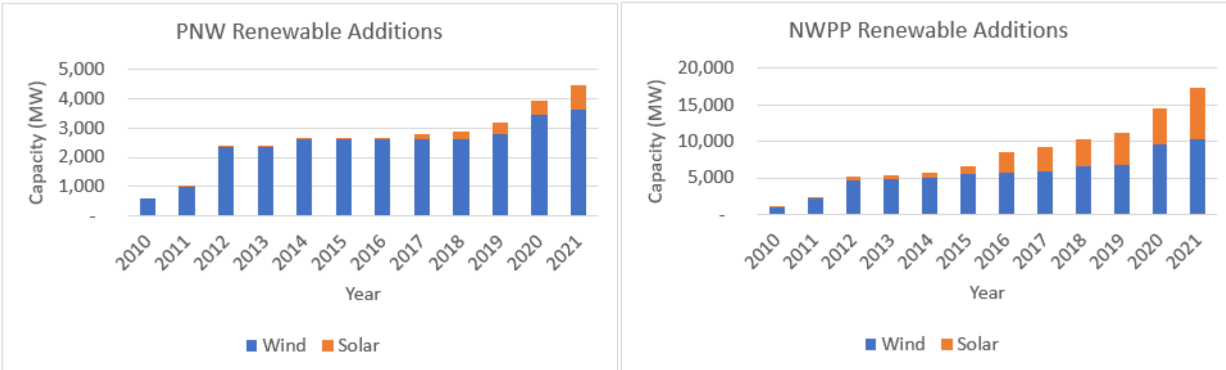


Every day the hydro system ramps above its baseload value to meet the morning and evening peaks. The peaking portion of the system during this week was also about 7,000 MW. That is, the output was able to ramp from 7,000 MW to 14,000+ MW within a day (across a four-hour period).

5.2.3 Renewables

A significant amount of new renewable capacity came online in the PNW and the NWPP over the last two decades, as shown in Figure 18. Most of the additions in the PNW are from wind, with relatively modest amounts of solar in the last few years.

Figure 18: Renewable Energy Capacity Additions in the NWPP and PNW, 2010-2021[19]



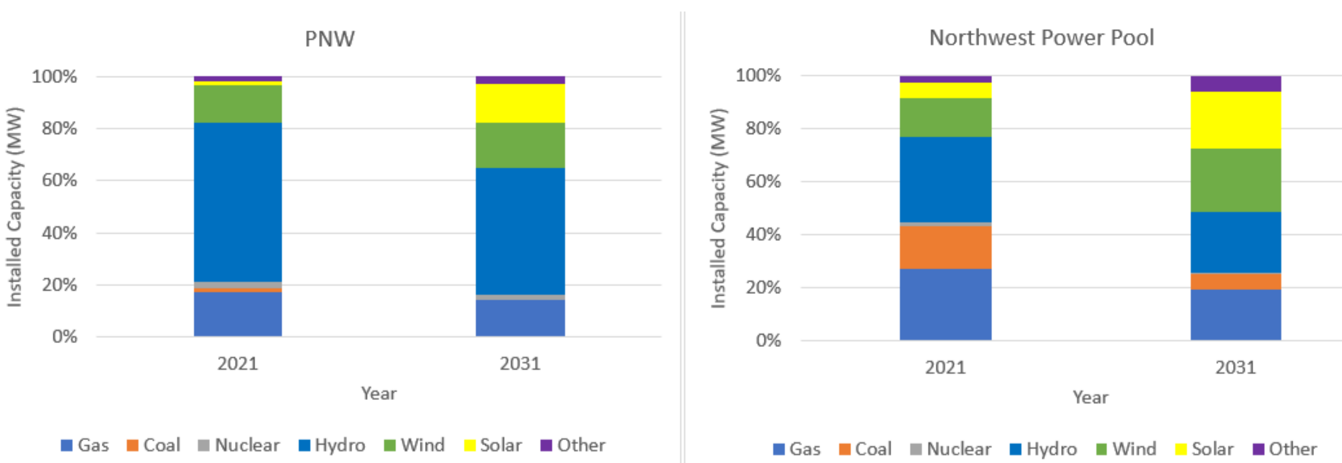
5.2.4 Future Supply Stack Forecasts

Ambitious state clean energy standards are expected to drive changes to the PNW supply stack, in terms of both retiring coal units and renewable additions. With the retirement of coal units, there is a significant need for new capacity additions within the PNW and the NWPP footprint to maintain reliability beyond what has historically been added.

EGPSC has developed a forward-looking model to forecast what the amount of capacity additions may look like in the future given current reliability needs, load growth, capital cost projections, policy goals, amount and quality of renewable sites, and transmission constraints.

The figures below show the EGPSC supply stack forecasts, in relative amounts. Renewable additions are expected to double as a percentage of total installed capacity from 16% to 32% in the PNW and increase from 21% to 45% in the NWPP by 2031. This is an example of the tremendous amounts of renewable capacity required to stay on track for current policy goals, and this puts a unique strain on the energy grid for reliability.

Figure 19: Forecast PNW and NWPP Generation to Meet Reliability and Policy Goals



[19] Source: EIA, EGPSC

Because renewables are intermittent in nature, the existing hydro and thermal fleet are needed for grid reliability to cover periods when the sun is not shining and the wind is not blowing. This is examined in more detail in the coming sections on reliability and scarcity events.

5.3 Resource Allocation: How Supply Is Deployed in the WECC Today

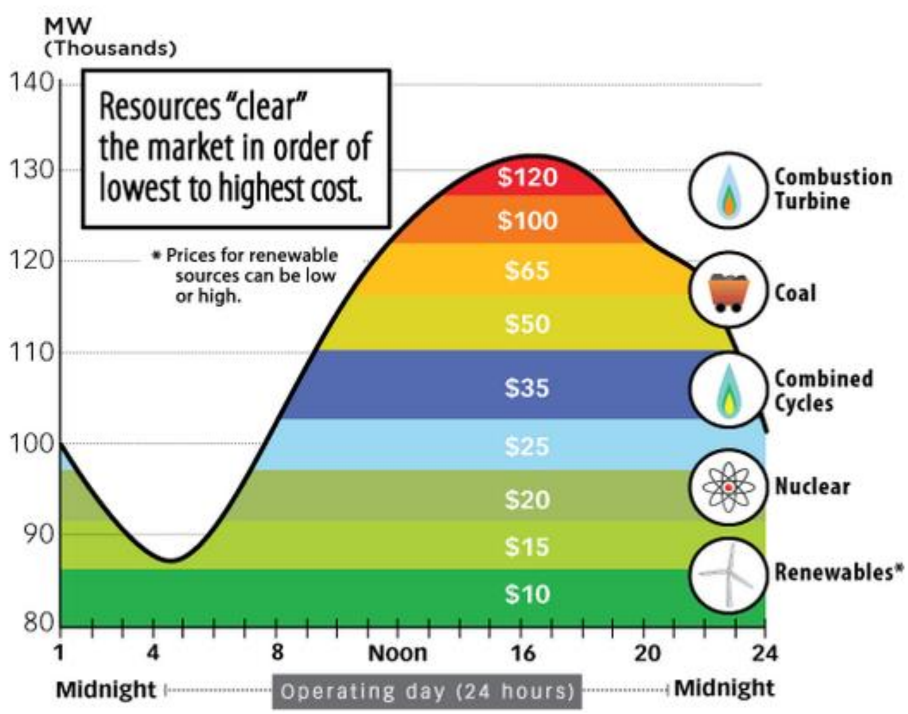
The following section summarizes how regional generators are turned on and dispatched to meet demand (and in what order), and where electricity comes from to meet peak demand when it spikes above already-online availability.

5.3.1 How Electricity Is Dispatched: Baseload vs Peakers

In a typical day, demand for electricity in a given region changes from hour to hour. Demand, or “load,” is usually lowest during the night, when most people are at home asleep. Load then increases throughout the day as individuals wake up, likely turning on the heat or air conditioning in their homes, go to work, and pursue the myriad daily activities that require electricity.

The figure below shows a typical shape for demand throughout a summer day, with load peaking in the late afternoon when the temperature is the highest. The figure shows an example of the supply “stack”, with the lowest marginal cost resources at the bottom and the highest at the top. As demand increases, generation resources are deployed (added onto the stack) to satisfy the demand at the lowest marginal cost.

Figure 20. Example of Changing Resource Stack for Generation in a Single Day [20]



[20] Source: https://learn.pjm.com/three-priorities/keeping-the-lights-on/how-pjm-schedules-generation-to-meet-demand

Renewable resources such as wind and solar generation are usually deployed first, as it costs essentially nothing to produce energy once the generator is built, as long as the sun is shining and the wind is blowing. The next resources deployed tend to be nuclear plants as they have low per-MWh fuel costs and limited flexibility. Nuclear plants are then followed by coal plants and combined cycle natural gas plants.

Coal, gas (particularly combined cycle), and nuclear plants, are referred to as "baseload" plants as they work best when running at near-full output for long periods of time. The downside to these sources of generation is that they can be slow and/or expensive to turn on, meaning that they are better used to generate for longer periods of time.

During the afternoon when load is at its highest, the less costly resources will be usually be fully utilized but still not producing enough able to satisfy demand. During these times of scarcity, the grid often turns to generators known as "peakers," combustion turbine (CT) units fueled by natural gas. While these resources have higher marginal costs than the baseload resources, they are flexible and nimble, able to be turned on and off rapidly in response to needs.

Peaker units occupy a unique and critical niche in the electricity ecosystem and provide much-need reliability. When demand is unusually high or less costly resources are not producing (e.g. a cloudy, windless day), peakers are required to ensure electricity demand is satisfied.

5.3.2 Role of Peakers in Areas with Significant Renewables

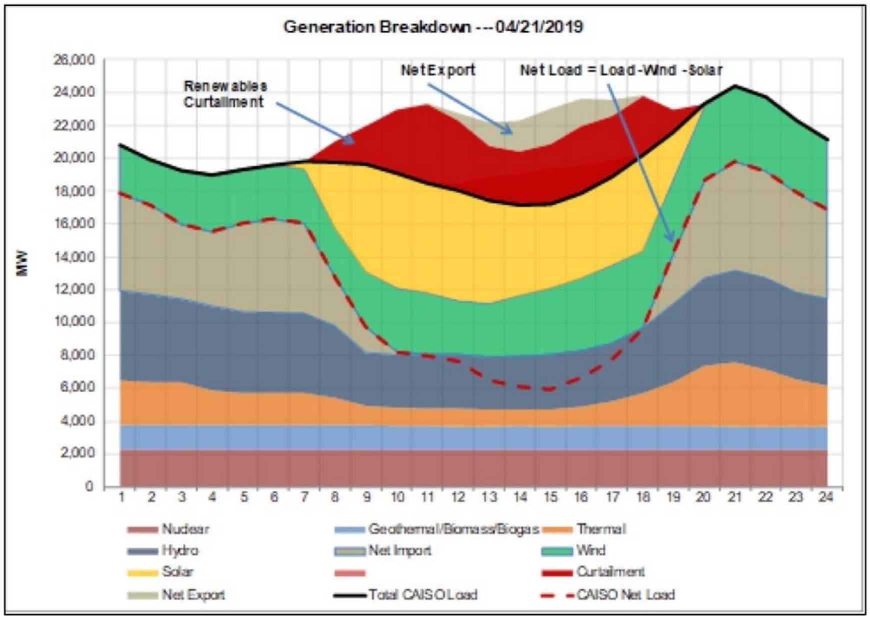
In areas where renewable generation is heavily used, including most of the WECC, peakers—or some form of flexible, fast start generation—are even more essential. Adding significant quantities of renewables to the grid has resulted in an increased need for peakers in the region. There are three primary reasons for this:

- First, renewable production is limited to the available resource (sun shining or wind blowing). The underlying resource can be quite volatile. Peakers provide flexibility to the grid to manage this volatility and ensure that supply and demand remain balanced.
- Second, the addition of significant amounts of solar to the grid has created a "ramping" challenge during the afternoon/evening hours when the sun goes down. During that period, demand tends to be increasing exactly when the solar production is declining. The solar energy that was available at 3pm must be replaced by another source of generation in the evening. Peakers provide this resource.
- Third, low-cost renewables often suppress the price of electricity during the middle of the day. During many months, these low mid-day prices make it impossible for baseload plants to run with a positive margin (energy revenue exceeds fuel and operating costs). This removes combined cycle power plants from the supply stack, resulting in increased reliance on the nimble, fast-response peakers.

The figure on the following page shows an example of dispatch in a grid with a significant amount of renewables in the supply stack.

The figure shows the generation stack throughout an example day, 4/21/2019, within the CAISO. On a day like the one illustrated in the figure, solar generation is plentiful during the middle of the day, but decreases and then disappears when the sun goes down. This leaves a large generation gap during a time of high demand.

Figure 21. Example Generation Profile with Significant Renewable Generation [21]



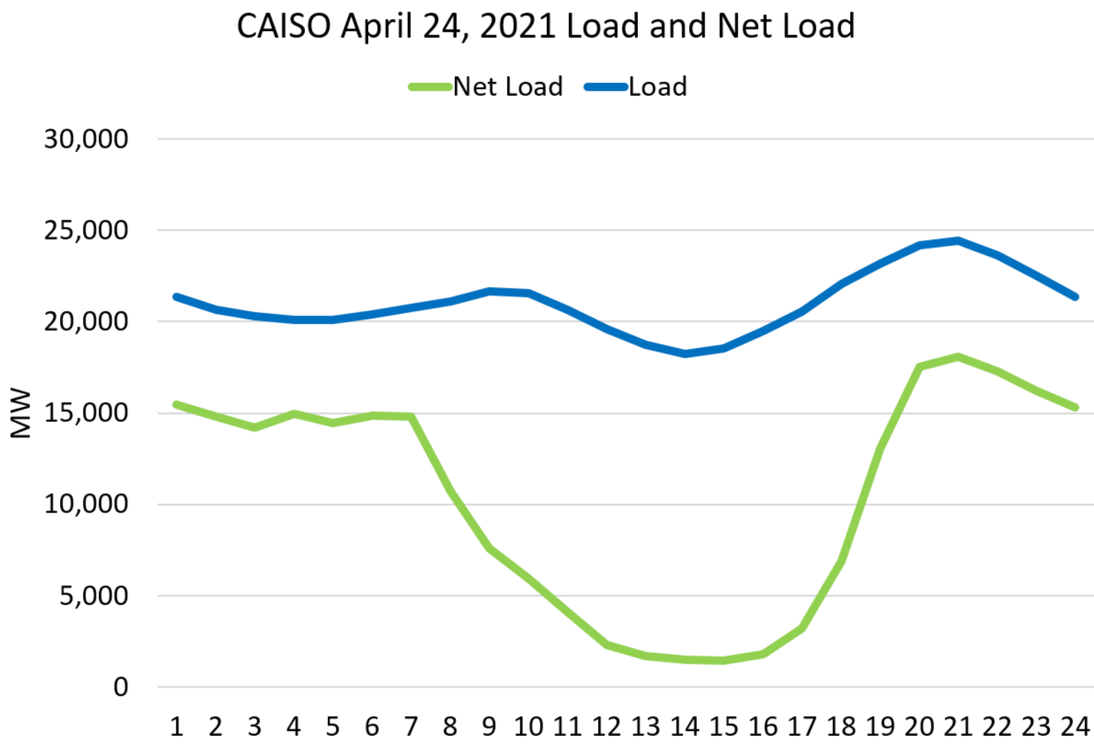
In order keep the lights on, peakers are heavily relied on in California and the Desert Southwest to make up this gap. Thermal generation is the orange section in the graph. While some thermal generation is running throughout the day, there is a large ramp up during the evening hours as solar comes offline. The other major source of ramping for the CAISO is imports (tan section), which also include significant amounts of thermal generation. The CAISO actually switches from importing power to exporting it during the middle of the day, and despite this amount of flexibility, they still must rely on peakers that can ramp up quickly as solar comes offline.

The increased reliance on peakers stemming from higher solar penetration rates is most acute in the CAISO. As more and more solar has come online, the "net load" (defined as load minus wind and solar generation) has dipped farther and farther down during the middle of the day. This has resulted in the now-infamous "duck curve", shown in the figure on the following page, for April 24, 2021.

The duck curve is what creates the ramping problem for the CAISO: as all the solar generation comes offline, something has to replace it in order to fill the evening peak load. California meets this net load ramp through a combination of internal resources as well as imported resources from the PNW and the Desert Southwest. Importantly, the steeper the net load ramp, the greater the need for flexible peaking resources and/or imports.

[21] Source: http://www.caiso.com/documents/windpowerplanttestresults.pdf

Figure 22: Example Net Load "Duck Curve," April 4, 2021 [22]



5.3.3 Imports and the Transmission Landscape

When regional supply produces too much or too little to meet regional demand, or has excess capacity available to help neighboring regions that have or need excess electricity, we look to the transmission system to import and export electricity for the good of the larger region as a whole.

The amazing benefit of the PNW transmission system is the ability to easily move electricity across long distances. The WECC transmission system is unique in the United States. It is possible to move electricity from Canada to Mexico by crossing the BPA and the CAISO systems. Canadian hydroelectricity routinely moves from British Columbia to California and the Southwest. During the spring runoff, carbon-free hydro power moves from Mid-C to California. Coal and wind generation in Montana moves into the PNW to meet load. It truly is a regional market, and neighboring regions rely on each other to balance the grid.

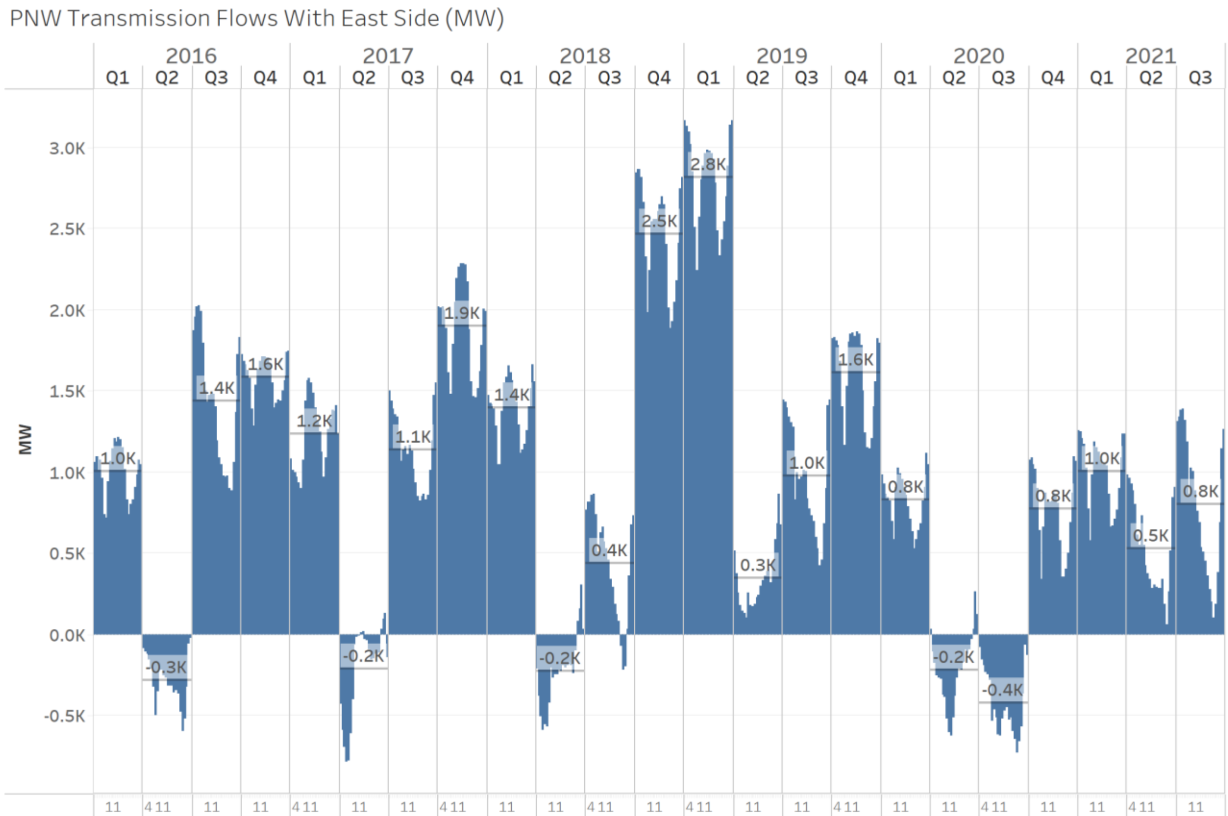
5.3.3.1 Transmission Flow Patterns Between PNW and Neighboring Regions

Transmission is the lifeblood of WECC markets. Diversity of supply and demand enables the region to reliably operate the grid at a lower cost than a grid with less interconnectedness. These connections have provided significant benefits over a long period of time. There are three important transmission paths in the PNW: British Columbia (BC), Montana (MT) and Idaho (ID), and AC/DC to California. Each transmission path plays a different role in maintaining the supply and demand balance across regions. The figure below shows patterns of use associated with the

[22] Source: https://www.enerdynamics.com/Energy-Currents_Blog/The-Duck-Curve-Becomes-Extreme-in-California.aspx

"tie lines" (transmission lines connecting one region to another) connecting Oregon and Washington to Montana and Idaho.

Figure 23: Transmission Between PNW and Montana & Idaho

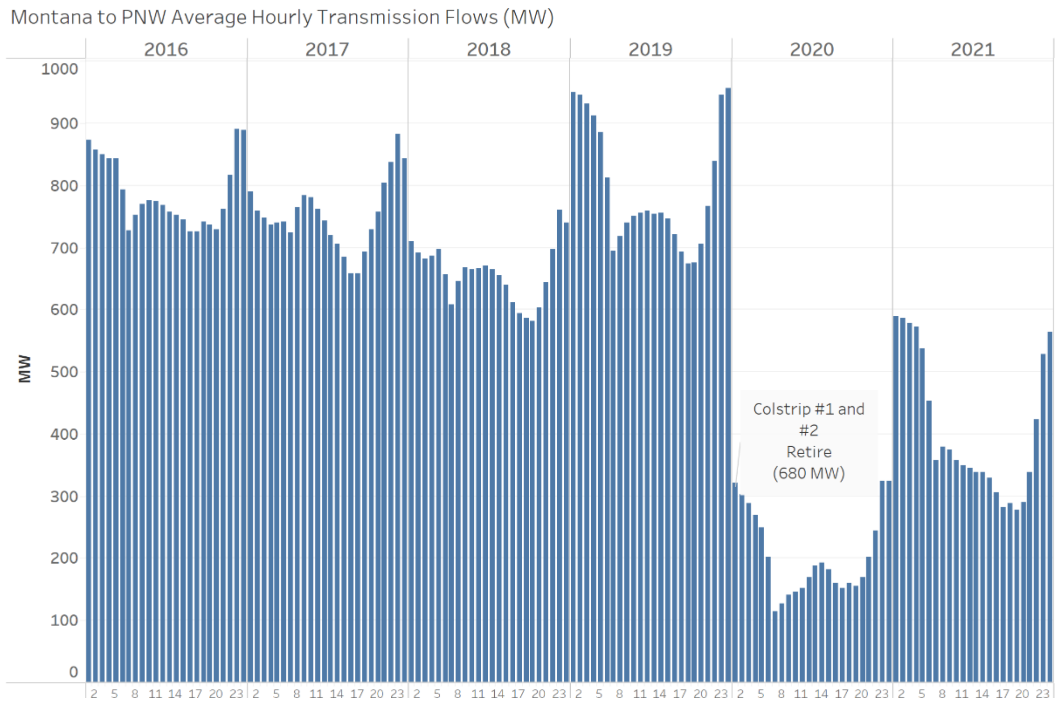


The figure shows average hourly flows (hours 1 to 24) for each quarter from Q1 2016 through Q3 2021. As shown, the PNW consistently imports energy from Montana and Idaho during the winter months and exports small amounts to the East side during the spring months.

During the Q3's, the flows on the line exhibit greater variability: in some years the PNW is a net importer while in others the PNW is a net exporter. One important source of flows to the PNW from the east is the large intertie connecting the Colstrip power plant in Montana to utilities in Oregon and Washington. For decades, Puget Sound Energy, Pacificorp, and Portland General Electric have been sourcing significant supply from Colstrip. However, two units at Colstrip were retired in January of 2020, reducing Colstrip output by 614 MW. There appears to be a decline in flows in the figure above starting in 2020. If we focus only on the transmission line between MT and the PNW the Colstrip retirement becomes even more pronounced.

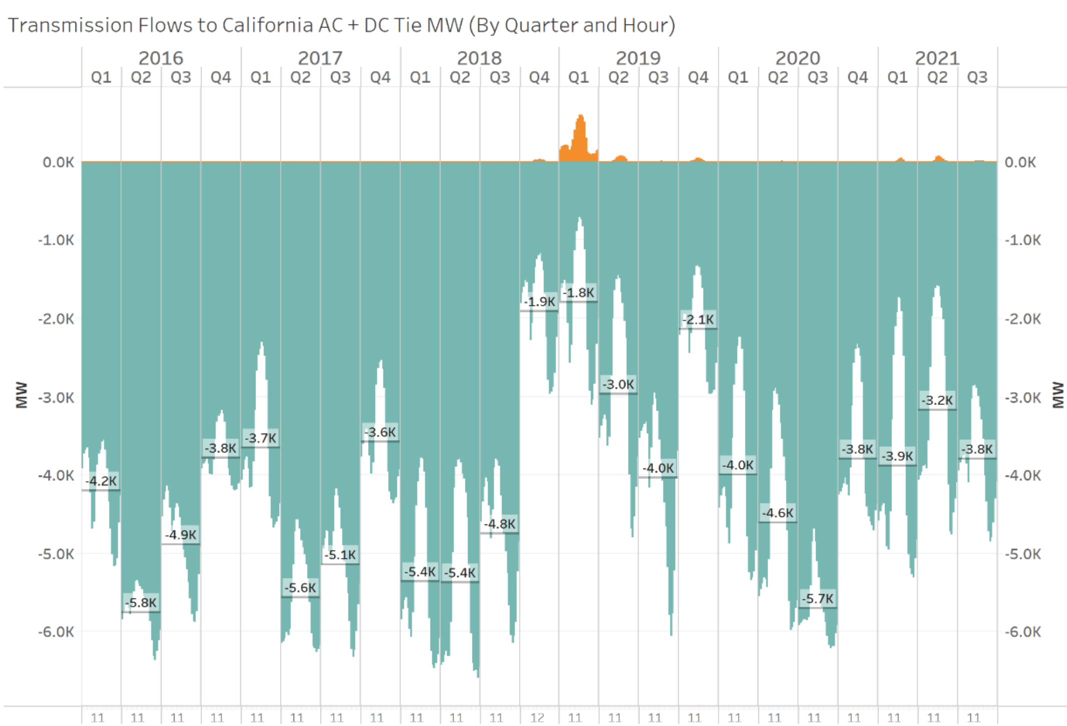
The figure on the following page illustrates how average flows from Montana to the PNW dropped precipitously in 2020 once the Colstrip units retired. These historical imports, which have provided critical balance to the PNW grid during times of past scarcity (as discussed later on), are gone and cannot be counted on to show up again.

Figure 24: Transmission from Montana to PNW



The figure below shows combined AC/DC flows between the PNW and CAISO. Negative numbers show PNW net exports to CAISO, while positive numbers indicate imports. The PNW is overwhelmingly an exporter. While CAISO routinely exports excess solar to the PNW, it rarely provides significant supply to the PNW during times of scarcity. In fact, many PNW resources are committed to supply CAISO loads via long-term energy and Resource Adequacy contracts.

Figure 25: AC/DC Flows Between PNW and CAISO



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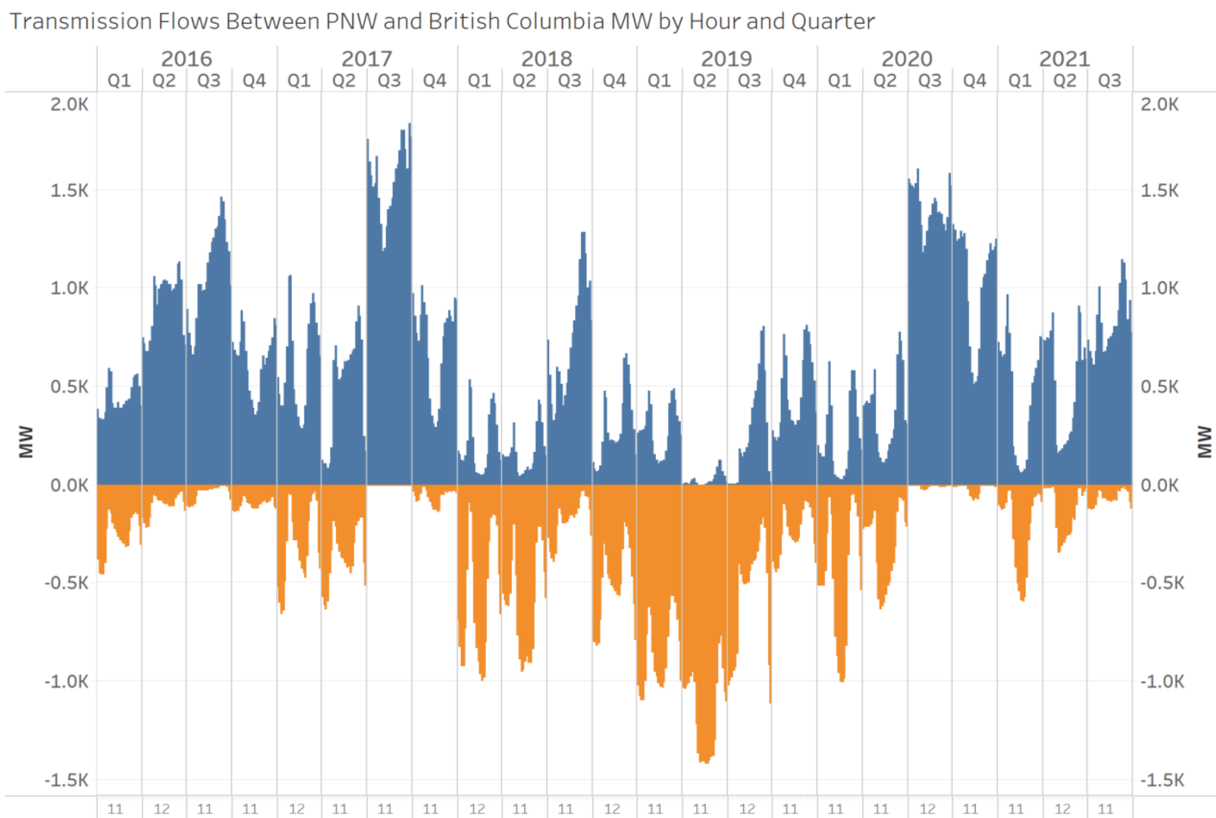
In the following figure showing transmission flows between PNW and BC, positive numbers reflect imports from Canada into the US while negative numbers reflect exports to Canada. The total flows across a year are a function of hydro supply in British Columbia. During low hydro years, British Columbia may be a net importer and during high hydro years they will be a net exporter. There is a seasonal pattern as well, where Canada refills its storage projects during the spring and then sends that stored energy south during the summer. There are also daily patterns, where excess energy is exported to Canada during the solar hours and off-peak hours and then returned during the critical morning and evening ramp hours.

Figure 26: Transmission Between PNW and British Columbia (BC)

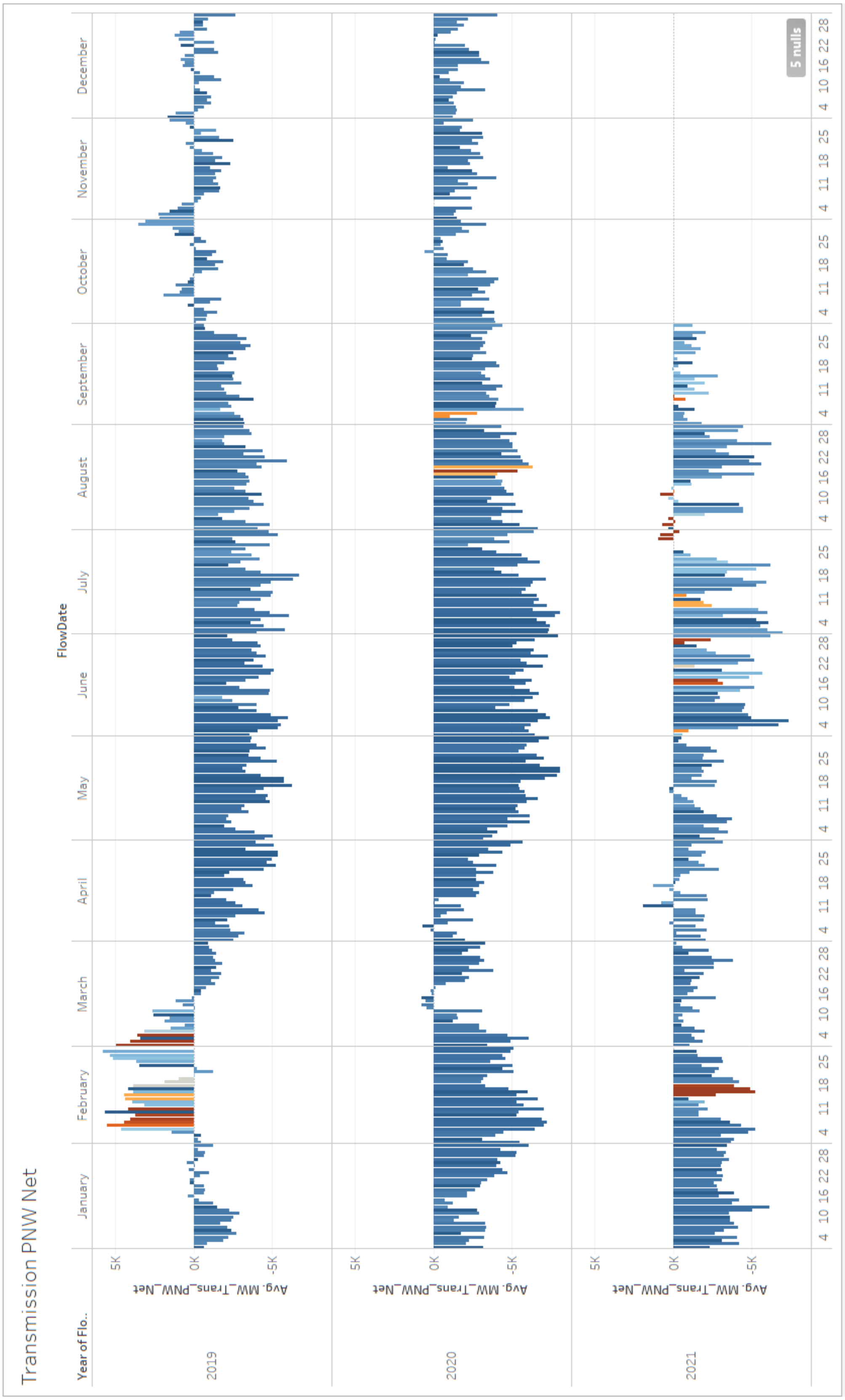


5.3.3.2 Transmission Flows During Critical Periods

Throughout the analysis, we will differentiate between the routine production and flow of energy and the acute need for reliable capacity when system conditions are tight. In the past section, we looked at transmission flows regions as routine patterns, and in this section we look at transmission flows between regions during times when system conditions are tight.

The figure on the following page shows average PNW net transmission flows by day from Q1 2019 through Q3 of 2021, where a negative number represents an export and a positive number represents an import. The bar color depicts the average peak price at Mid-C for each day. As we discuss in detail later, the price at Mid-C rises as energy in the region becomes increasingly scarce.

Figure 27: Net PNW Transmission, 2019-2021



There are several notable instances where high prices coincide with high imports into the PNW region. These include February and March of 2019 as well as certain days during August of 2021. Of note also are the high-priced days during August of 2020 where the PNW was a net exporter to California; the high prices in this instance were driven by scarcity – which led to rolling blackouts in California, as discussed further in the scarcity event case studies.

5.3.3.3 Transmission Risk During Times of Scarcity

While transmission flows create great benefits for all regions, they also pose risks during times when energy is in short supply. During acute reliability events, the PNW can import over 6,000 MW of energy from surrounding regions and typically imports around 500 MW. Should key transmission lines become unavailable at those critical times, the PNW would be forced to increase in-region supply to make up the shortfall.

The PNW routinely relies on supply from Canada and Montana to balance the grid. On rare occasions, electricity from California has also been brought to the PNW to meet acute needs. However, history shows us there is a real risk that the transmission lines can be forced out of service at critical times.

Of course, the transmission owners and operators take great care to maintain the transmission grids and prevent this from happening. However, despite this care, extreme weather events can wreak havoc on the transmission grid. In the last several years, we’ve seen examples of transmission outages that have materially impacted the reliability of the grid.

The August 2020 blackouts in California are one such example.[23] Prior to the blackouts, in May 2020 there was a storm that impacted the California Oregon Intertie (COI). This caused a capability reduction of approximately 650 MW through August and thus limited power exports to California. CAISO instituted rolling blackouts on August 14th and August 15th, curtailing two phases of 500 MW of load on the 14th for one hour and one phase of 500 MW on the 15th for 20 minutes. Had the AC intertie been fully available, there likely would have been sufficient supply to prevent the blackouts.

The official root cause of the blackouts was threefold: 1) extreme weather events causing greater demand than expected, 2) insufficient resource mix to provide power, and 3) day ahead market practices. While not listed as one of the three root causes of the blackouts, the transmission de-rate was a contributing factor, as additional imports would have further supplemented the resource mix within California. These types of outages can impact the PNW as well during times of scarcity when power may need to be imported from California.

5.3.3.4 Wildfire Risk Increases Transmission Risk

Fire is a constant threat to transmission reliability during the dry months. A recent example of the impact of wildfires on transmission lines was in 2021 during the Bootleg fire in Oregon. The Bootleg fire was a large (413,717 acre) fire that started near Beatty, Oregon[24] on July 6, 2021. During this time there was extreme heat throughout the west causing energy conservation alerts in California. On Friday July 9, CAISO issued the following warning due to the fire threat:

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[23] http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

[24] https://inciweb.nwcg.gov/incident/7609/?_kx=LIbWe-LUw11-la1HBOiLBtUavbTKEXXu_3vclBggS4HI-nnLUJZvjM_NetnzCC7J.V3MAVE

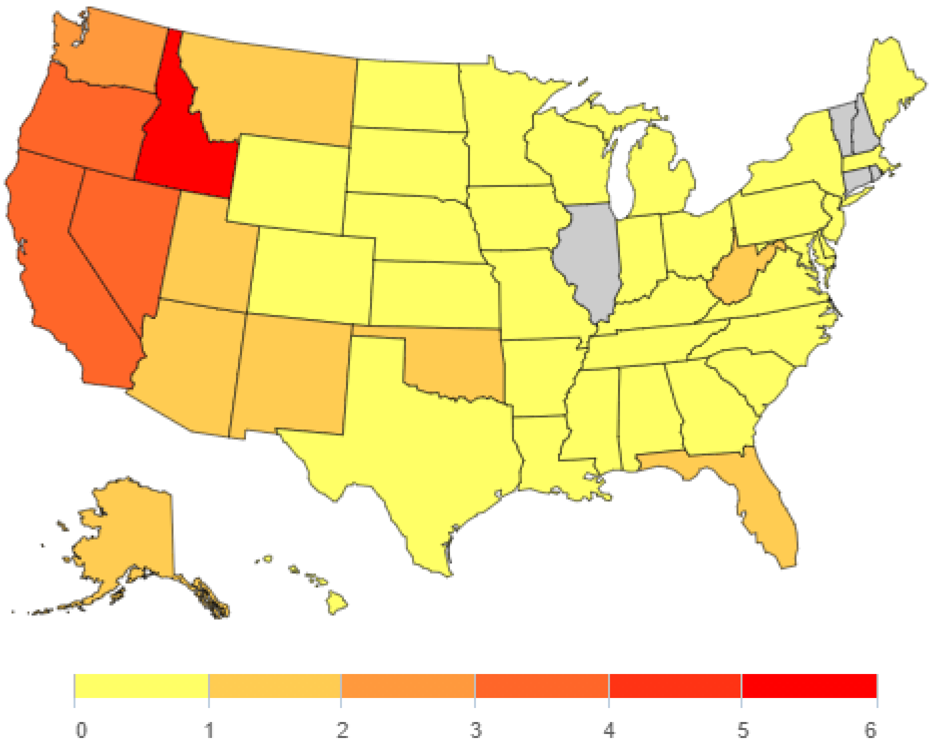
> *"The California ISO hereby issues a CAISO Grid WARNING Notice effective 07/09/2021 17:00 through 07/09/2021 22:00. Reason: Due to loss of resources and fire threat to the transmission system. CAISO is forecasting a resources deficiency with all available resources in use or forecasted to be in use for the specified time period. If not already declared CAISO may request the Reliability Coordinator to declare an EEA-1. If the Emergency Demand Response Programs are dispatched then CAISO may request the Reliability Coordinator to declare an EEA-2. Conservation efforts are encouraged for the time period specified in this notice. Energy Market Participants are encouraged to offer additional Supplemental Energy and Ancillary Service bids. Refer to the CAISO System Emergency Fact Sheet (http://www.caiso.com/Documents/SystemAlertsWarningsand EmergenciesFactSheet.pdf) for additional detail. Monitor system conditions on Today's Outlook (http://www.caiso.com/TodaysOutlook/Pages/default.aspx) and check with local electric utilities for additional information. Notice issued at: 07/09/2021 14:05"*

The AC and DC lines exporting power from the PNW to California were significantly de-rated due to the Bootleg fire. In fact, at one point, a total of 5,500 MW of reduced transmission capability occurred. California kept the lights on during the period, but it highlights an important example of the impacts of wildfires on the PNW transmission grid.

While the previous example showcased impacts to the CAISO, the PNW also relies heavily on importing electricity into the region during times of scarcity. Anyone who has spent time in the PNW in the summer has experienced the impacts of wildfires. Every summer, smoke fills the region, adversely impacting air quality from June through September. The region has experienced devastating wildfires in lush river valleys that one would have never expected to suffer from events typically brought about by dryness and heat. Rarely do these wildfires provide advance notice. They come as a surprise and change rapidly in real time. This poses significant risks to the electricity grid.

Despite the perception of Oregon and Washington as rainy, the Western US as a whole is extremely susceptible to wildfires due to an abundance of fuel and extreme drought. Within the Western US, the average acres burned historically has been highest in Idaho, Oregon, California, and Nevada. There is a climate change-induced increase in the area burned by fires. Unfortunately for the energy sector, these fires predominately occur in the summer months when electrical demand can be at its peak.

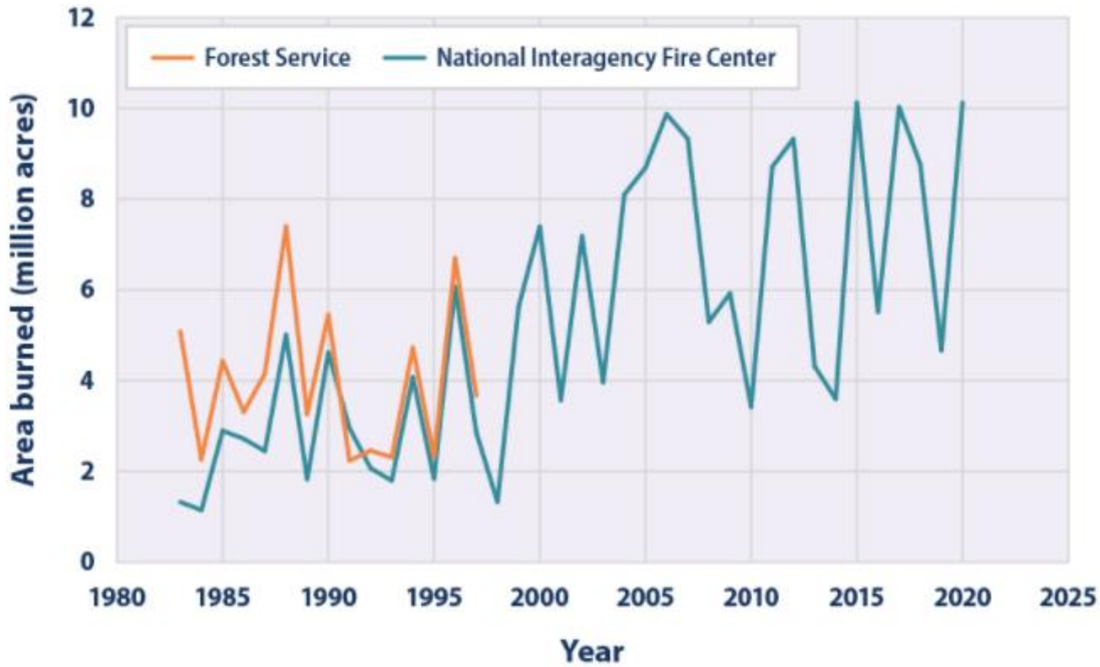
Figure 28: Average Annual Burned Acres by State, 1984-2018 [25]



Not only does the PNW experience similar levels of burned acreage as more well-known wildfire hotspots, but it is enclosed by states that also are regularly devastated by wildfires. Transmission within the region and connecting the PNW to surrounding regions is regularly threatened. The risk is not just that a transmission line may be burned down: lines are often de-rated in response to environmental conditions, reducing the number of MW flowing to prevent *starting* a wildfire, as there is a risk that the electrical equipment might spark and become the source of a new fire.

[25] Source: EPA, https://www.epa.gov/climate-indicators/climate-change-indicators-wildfireswildfires#:~:text=Beyond%20the%20human%20and%20societal%20impacts%2C%20wildfires%20also,also%20release%20carbon%20dioxide%20more%20gradually%20through%20decomposition

Figure 29: Wildfire Total Acreage Burned in the U.S., 1980-2020 [26]



The risk posed by wildfires is not declining. The number of burned acres per year has been on a steady upward slope since the 1980s. The West as a whole is getting drier. January through mid-April of 2021 were the driest on record in California, and among the warmest[27]. In 2020, areas around Salem, Oregon and the northern Willamette Valley were rated as having "extremely critical fire weather" for the first time in history[28].

Figure 30: Monthly Area Burned by Wildfires in the Western and Eastern U.S. [29]

[26] Source: EPA, https://www.epa.gov/climate-indicators/climate-change-indicators-

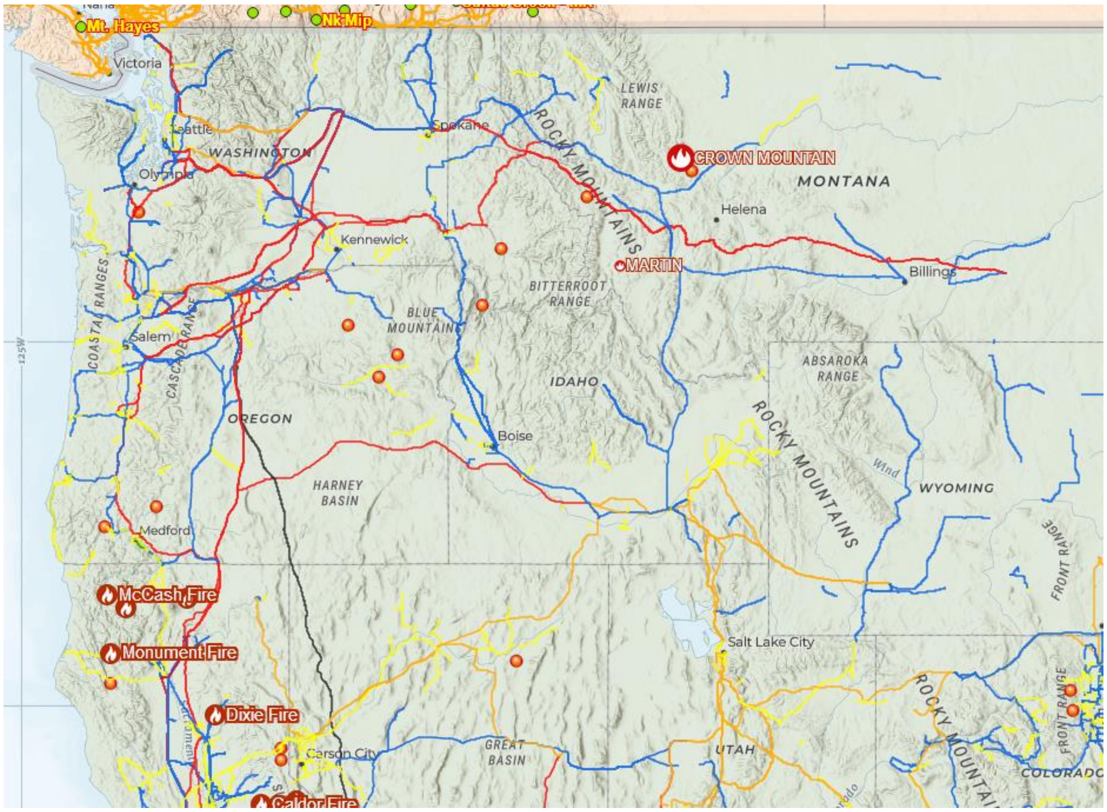
[27] https://weatherwest.com/archives/14111

[28] https://www.oregon.gov/energy/Data-and-Reports/Documents/2020-Biennial-Energy-Report.pdf

[29] Source: EPA, https://www.epa.gov/climate-indicators/climate-change-indicators

There is an enhanced risk of transmission due to wildfires in the West because of the long-remote stretches of terrain that transmission lines cross. This operational risk is illustrated by the wildfire transmission risk dashboard for WECC. As shown in the figure below this dashboard is only a snapshot of fire activity on the day it was downloaded but illustrates the long stretches of transmission lines in remote areas. Because of this, many transmission owners and operators have dedicated wildfire mitigation plans in place to reduce the risk to energy users[30].

Figure 31: WECC Map Showing Transmission Lines and Wildfire Activity [31]



The threat that fires pose to transmission lines has been increasing over the past few decades and will continue to increase for the foreseeable future. With no clear picture of where additional in-region generation might come from when transmissions lines are unavailable, and betting on imports becoming increasingly risky, the existing sources of regional generation are more critical than ever.

5.4 PNW Peak Resource Allocation

In most of the WECC, peakers are an essential part of the electricity supply stack for supplying flexible dispatch of energy, both to allow energy supply to follow intra-day load patterns as well as providing additional generation during longer periods of scarcity.

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[30] For example, the BPA Wildfire Mitigation Plan: https://www.bpa.gov/environmental-initiatives/sustainability/wildfire-mitigation

[31] Source: https://www.arcgis.com/apps/webappviewer/index.html?id=4a47216fe65542dfb8c742caf8458e58

5.4.1 Role of Natural Gas Peakers in the PNW

The "fast start" dispatch of peakers is defined in this section as an instance where a natural gas-fired peaker unit generates electricity for less than five consecutive hours.

5.4.1.1 Natural Gas Peaker Dispatch in WECC Outside of PNW Compared to Within PNW

Fast start peakers are commonplace throughout the WECC during times of high demand and/or low supply—with the exception of the Pacific Northwest.

In California as well as in the Desert Southwest, fast start peaker dispatches occur in approximately one-third to one-half of all hours. Peaker dispatch in these regions follows general load patterns within each day, with peakers used in the morning and evening periods to meet increased demand. However, in the PNW, peaker dispatch is both infrequent and very small in scale despite similar patterns in load.

The table below shows the quantity and percent of time peakers are used, by region. NP15 is Northern California, SP15 is Southern California, and DSW is the Desert Southwest.

Table 3. Peaker Use in the WECC by Region [32]

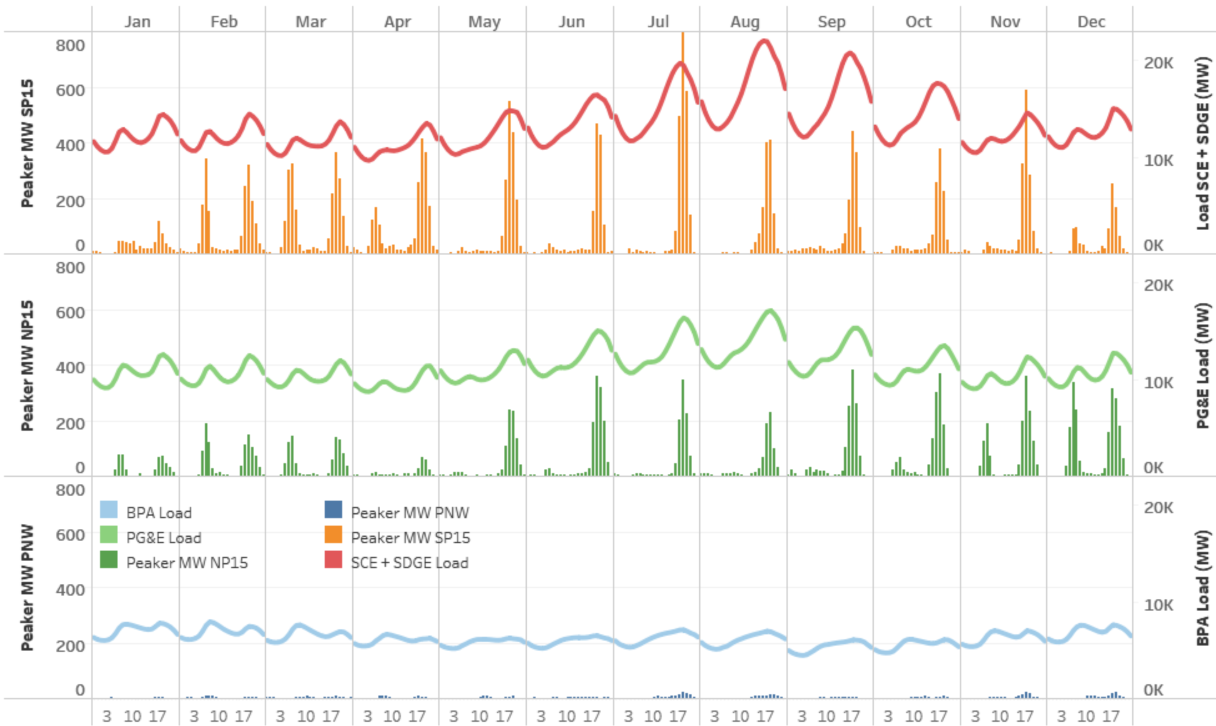
		2017	2018	2019	2020	% All Hours
WECC	# of Fast Starts	19,222	16,728	16,157	16,268	
WECC	# of Hours with Fast Starts	6,012	6,067	5,692	5,953	68%
PNW	# of Fast Starts	1,347	945	432	490	
	# of Hours with Fast Starts	1,672	1,431	682	871	13%
NP15	# of Fast Starts	4,288	4,111	4,188	3,789	
	# of Hours with Fast Starts	2,906	3,088	2,618	2,692	32%
SP15	# of Fast Starts	6,355	5,260	5,354	5,025	
	# of Hours with Fast Starts	3,502	3,489	3,486	3,359	39%
DSW	# of Fast Starts	7,232	6,412	6,183	6,964	
	# of Hours with Fast Starts	4,597	4,251	4,248	4,313	50%

- The first row in region, *# of Fast Starts,* sums the total number of times a peaker was used for a fast start dispatch (generation of < 5 consecutive hours) in a given year for each individual unit. For example, throughout the WECC in 2020, there were 16,268 individual peaker starts spread across 5,953 hours. With 8,760 hours in a year (8,784 in a leap year) a peaker is running in 68% of those hours.
- The PNW averages under 1,000 fast starts per year, with each of the other three regions averaging at least 4,000 unique starts per year.
- Regions outside of the PNW relied on peaker dispatches between 32% (NP15) and 50% (DSW) of all hours from 2017-2020. In the PNW, a peaker dispatch took place during only 13% of all hours.

[32] Table represents analysis performed by EGPS using hourly generation data from EPA.

The figure below illustrates this point graphically. Each pane has a double y-axis, with average peaker dispatch on the left and average load on the right. The x-axis shows hourly averages for each month. SP15 is the top row, NP15 is the middle row, and the PNW is the bottom row.

Figure 32. Average Hourly Load and Peaker Generation (MW) by Month, 2020



- The figure plots the average hourly electricity load and average hourly MW of energy from fast start peaker dispatches by month during the year 2020. Each pane therefore represents an hourly demand and peaker supply profile for a "typical" day in a given month.
- Three regions are shown: SP15, NP15, and the PNW. SoCal Edison (SCE) and San Diego Gas and Electric (SDGE) demand are summed for SP15 load, Pacific Gas and Electric (PG&E) demand is used for NP15, and BPA load is shown for the PNW.
- For SP15 and NP15, hourly peaker generation follows the load profile closely in each month. In the fall and winter, generation rises to peaks in the morning and late afternoon/early evening periods when demand ramps upward and falls close to zero during the midday and nighttime periods when there is no demand. During the summer when morning heating demand disappears and load peaks only once on a typical day in the evening, peaker generation shifts to follow the pattern.
- In the PNW, peaker generation is insignificant, averaging less than 25 MW even during the evening demand ramp in July.

5.4.1.2 PNW Natural Gas Deliverability Risk

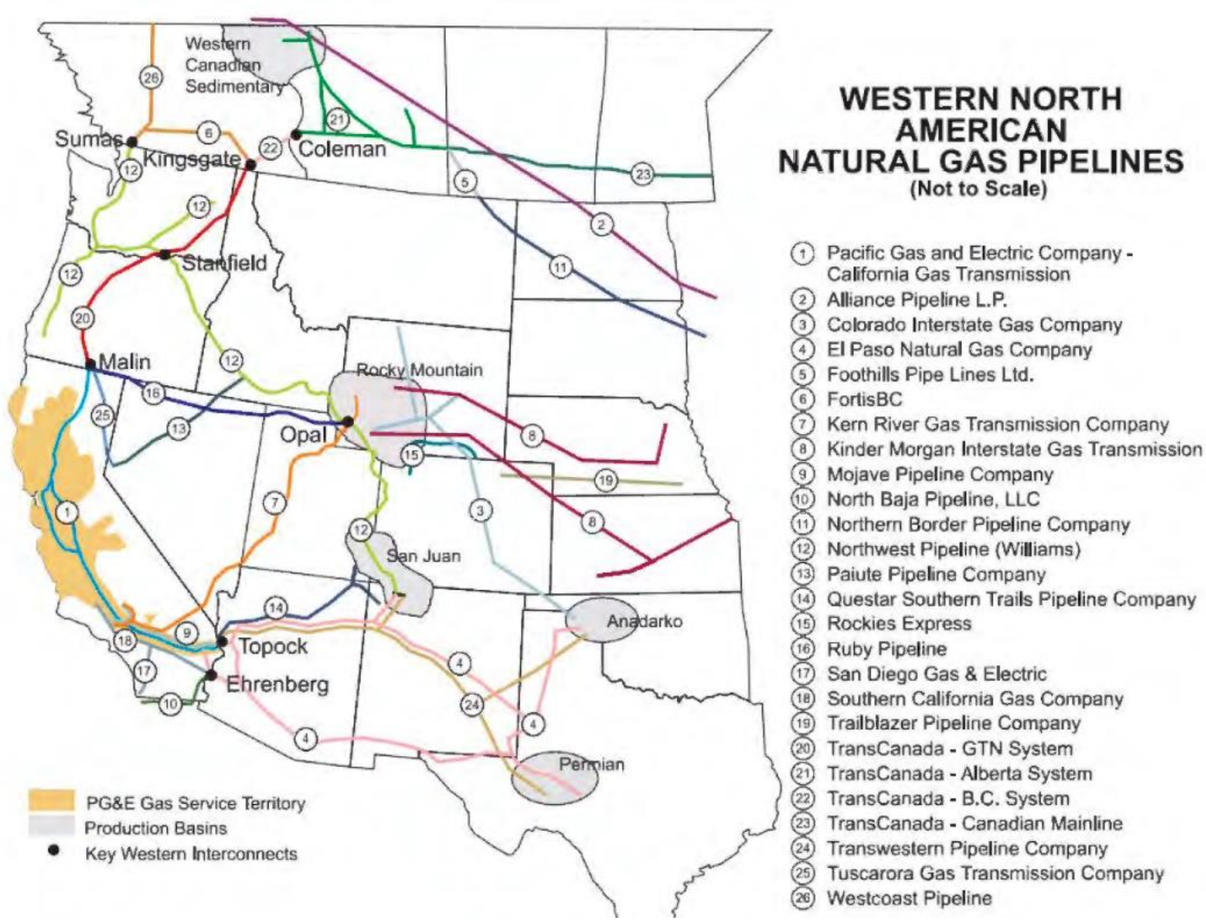
Natural gas is the single largest source of electricity generation in the WECC. It plays a key role as the fuel for both baseload generation units and flexible peaker units. In every hour of every day there are scores of natural gas plants running in the WECC.

5.4.1.2.1 Introduction to the PNW Natural Gas Supply System

In the PNW, natural gas plants are a vital part of the electricity supply during all portions of the year except a few weeks in the spring when loads are low and hydro supply is surging. Natural gas supplies are moved by interstate pipeline, which are as much as 1,000 miles away from the demand centers of electricity generators.

The figure below shows the major natural gas supply basins in the West and the interstate pipelines which move that supply to demand.

Figure 33: Natural Gas Supply Basins and Delivery Pipelines, Western U.S.



Source: https://efiling.energy.ca.gov/GetDocument.aspx?tn=228907&DocumentContentId=60278

In the West, the PNW, Arizona, and Nevada all rely on natural gas that is shipped hundreds or thousands of miles from its source, with the exception of intra-state natural gas supply within California.

The table below shows the relative size of the different pipelines serving the WECC.

Table 4: Natural Gas Pipelines Serving the WECC [33]

Owner	Pipelines	Capacity MMcf/day	% Total	Running % Total
El Paso	CO Interstate, El Paso, Mojave, WY Interstate	10,690	46%	46%
Williams	Northwest Pipeline	3,500	15%	61%
TransCanada	Gas Transmission NW, North Baja	3,400	15%	76%
Questar	Questar Pipeline, Questar Southern Trails, Overthrust	2,180	9%	85%
Mid American	Kern River	1,700	7%	92%
Other	Transwestern, TransColorado, Tucarora	1,773	8%	100%
Total		23,243	100%	

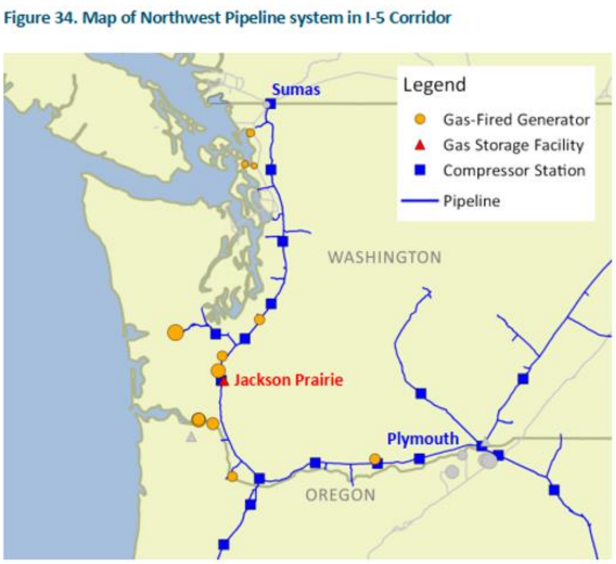
The electricity industry prides itself on running reliable systems. This includes having spare generating capacity available at all times and managing a web of transmission lines which ensure that generation can be delivered to load at all times. The key to reliability is redundancy.

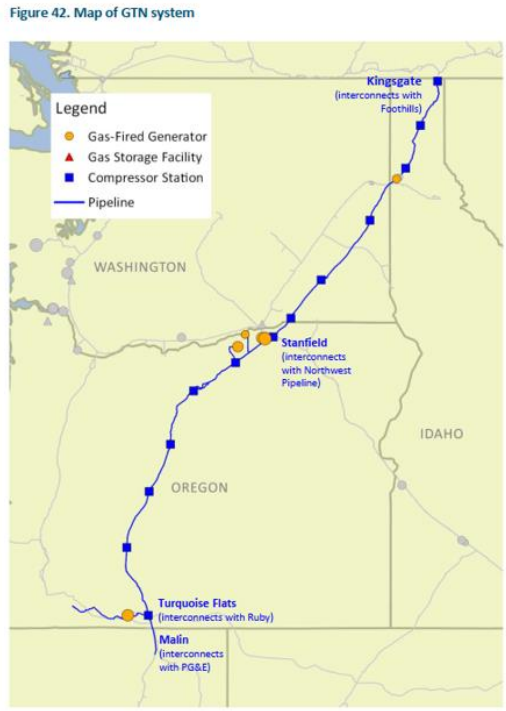
The natural gas pipeline system lacks such redundancy. Five pipelines account for 92% of the natural gas delivery capacity into the WECC. If any of these pipelines experience outages, that outage impacts both the market where the natural gas is consumed, but also, all other electricity markets in the WECC as the lost gas generation in one region will impact what happens in other regions. Approximately 65 million people in the Western states rely on the natural gas or the electricity generated from the natural gas delivered through these pipelines.

The PNW gas supply situation is no different than the rest of the west. The figures on the following pages come from an E3 report evaluating the natural gas infrastructure adequacy in the WECC published in 2014.[34]

[33] The data for this table can be found in "Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric Perspective. Phase 2 Report" published in July 2014 by Energy + Environmental Economics.
[34] See "Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric Perspective. Phase 2 Report" published by Energy + Environment Economics (E3). See Figures 34 and 42. https://westernenergyboard.org/wp-content/uploads/2014/07/E3_WIEB_Ph2_Report_full_7-28-2014.pdf

Figure 34: PNW Natural Gas Pipelines [35]





The PNW relies on three pipelines to supply the region:

- The West Coast pipeline entering at Sumas
- The TransCanada pipeline entering at Kingsgate
- The Northwest pipeline entering at Stanfield

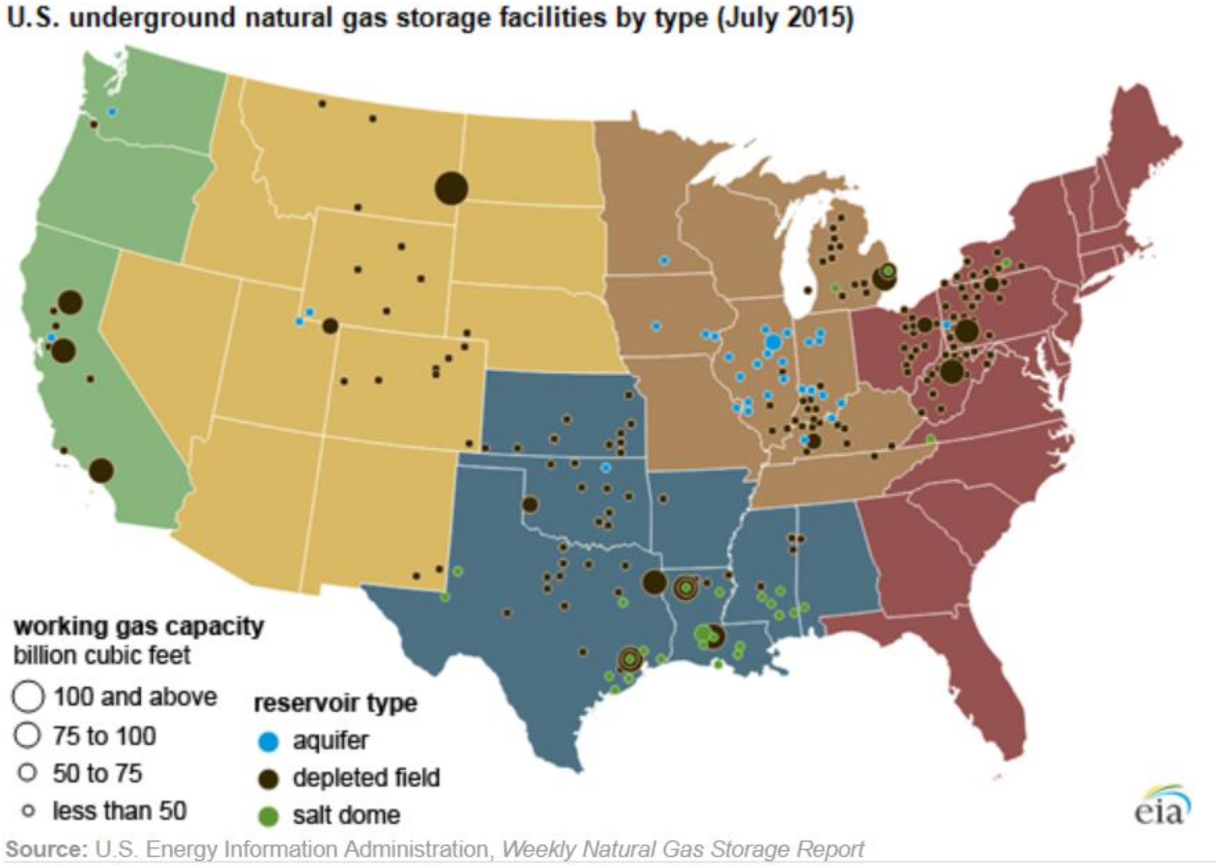
Much of the natural gas coming through Kingsgate is destined for the California market.

The natural gas delivery infrastructure also includes storage facilities located proximal to demand. The term "deliverability" in the natural gas business refers to the amount of natural gas that can be delivered by a natural gas local distribution company (LDC) via both pipeline and storage withdrawals.

The total deliverability is sized to the maximum expected demand. That is, the total deliverability is sized to total daily demand on the coldest day in the winter (natural gas planning is done based on cold weather). If a region has little storage, its deliverability is reliant on pipelines—the system of which, as mentioned before, has almost no redundancy in the west.

[35] Source: https://westernenergyboard.org/wp-content/uploads/2014/07/E3_WIEB_Ph2_Report_full_7-28-2014.pdf

Figure 35: US Natural Gas Storage Facilities



The map shows precious little natural gas storage capacity located in the PNW. The region has very little in-region storage buffer to draw from in the event there is a disruption on one of the three important natural gas pipelines serving the region.

5.4.1.2.2 Natural Gas Delivery Issues

The Western US has experienced a number of problems with natural gas deliveries in the last five years. These challenges include the following events:

- Southern California: There were a series of events from 2015 through 2020 which constrained deliveries of natural gas in Southern California. The Aliso Canyon storage facility can be seen on the map above as the large black circle in Southern California. Gas withdrawn from Aliso Canyon provides fuel to 17 natural gas-fired power plants and 11 million natural gas customers. Aliso Canyon experienced a massive natural gas leak, which extended from October 2015 through February 2016. As a result, the storage facility was de-rated both in terms of natural gas that could be held in storage as well as the withdrawal rate. This made the SoCal natural gas system vulnerable to problems. On October 1, 2017 a natural gas pipeline exploded in the California desert causing further restrictions on natural gas flows into Southern California. The system was able to limp along until the summer of 2018 when a heat wave hit during July and August. Demand for natural gas soared and the price of natural gas in the area jumped 10x from $4 per MMBtu to $40. Service on the pipeline was restored in 2020, more than two years after the explosion.

- Pacific Northwest: A 36-inch Enbridge pipeline blew apart and caught fire in October 2018 near Prince George, British Columbia, severely limiting gas flowing into the United States at Sumas. British Columbians were temporarily asked to avoid non-essential use of natural gas with one utility receiving only 40% of its usual flow of natural gas. Most of the natural gas-fired generation in Washington is served via Sumas. Local utilities pulled more natural gas from the Jackson Prairie storage facility in Washington. However, when cold weather hit the PNW in February and March of 2019, pipeline flows from Sumas were only 65% of normal and Jackson Prairie was almost out of natural gas. This resulted in price spikes and severe limitations to deliveries of natural gas to Washington power plants (as discussed further in the case studies).
- External Factors: In February of 2021 Winter Storm Uri slammed the state of Texas where much of the natural gas going to California is sourced. As a result of the storm, exports of natural gas from Texas were severely curtailed, especially those exports flowing to the West. The effects of these curtailments were felt most in Southern California while the surrounding regions felt the ripple effects as well.

5.4.1.2.3 Effects of Natural Gas Delivery Issues on the Electricity Market

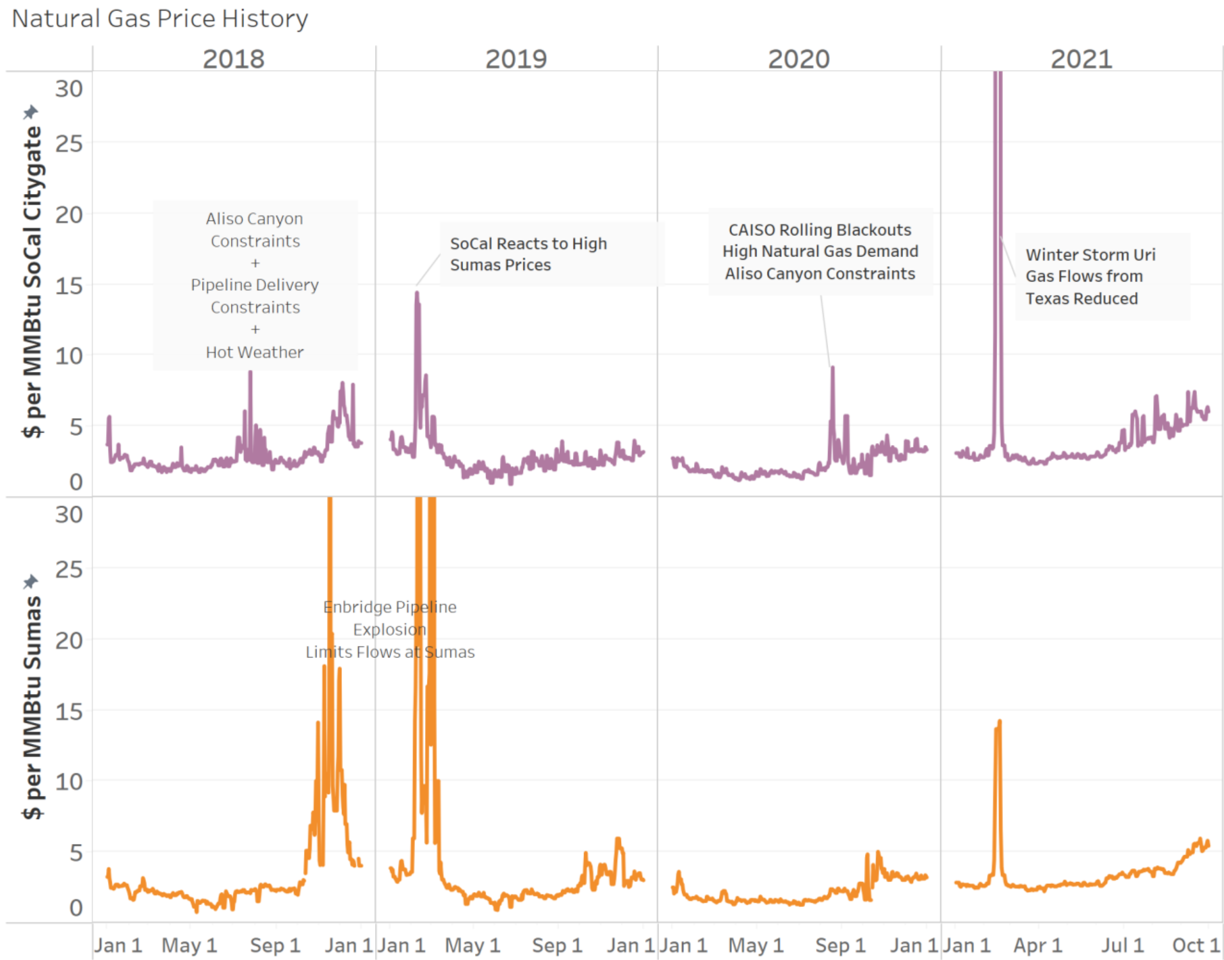
The story of challenges with the natural gas pipeline and storage system can be seen in the prices of natural gas. The figure on the following page shows the daily price of natural gas at two market hubs: SoCal Citygate which is the hub for Southern California and Sumas which is a hub in Washington.

As shown in the figure, each of the physical challenges on the natural gas system resulted in higher natural gas prices, and these higher prices effectively ration natural gas deliveries to the electricity generation fleet.

The top pane shows prices for SoCal Citygate which is the major natural gas trading hub in southern California and the bottom pane shows the natural gas price at Sumas along the Washington border with Canada. During this period the natural gas markets experienced the following challenges:

- Aliso Canyon Storage Constraints – A gas leak in the largest natural gas storage facility in California resulted in strong prices during the summer of 2018.
- Sumas Pipeline Constraints – From October 2018 through March of 2019 the Sumas pipeline which serves most gas-fired electricity generators in Washington had significant constraints. This led to reliability issues in electricity during February and March of 2019.
- More Alison Canyon Constraints – High temperatures in August 2020 led to huge demand for natural gas for power generation. Constraints on the Aliso Canyon facility led to limited availability of natural gas.
- Curtailed Natural Gas Exports from Texas during Winter Storm Uri – In addition to causing blackouts in Texas, Winter Storm Uri reduced natural gas well production in the Permian Basin. This limited the flow of natural gas to California causing natural gas prices to rise.

Figure 36: Natural Gas Price History, 2018-2021



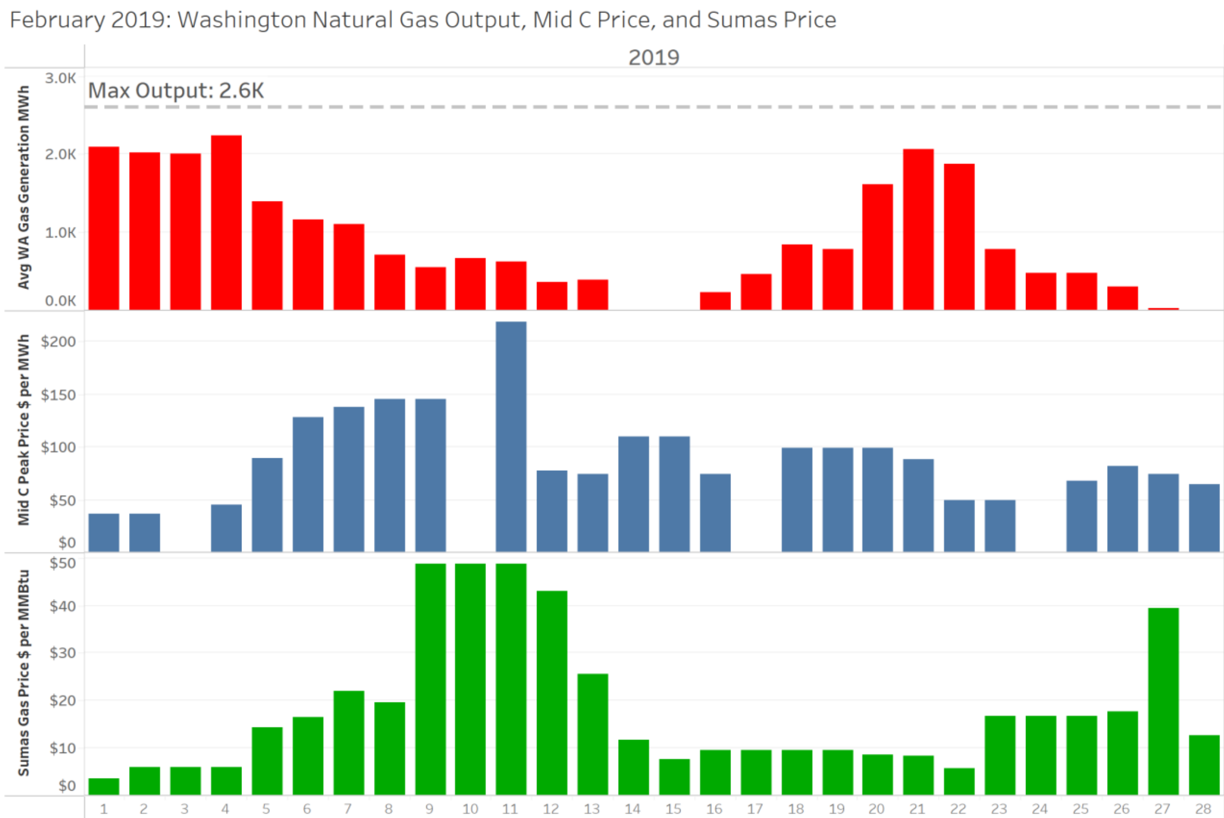
While none of these natural gas constraints has yet to lead directly to or be the primary cause of blackouts in the Western United States or the PNW, the conditions exist for significant natural gas delivery challenges under the right circumstances.

The next series of figures illustrates how the constraints on the natural gas system impact the electricity market.

In the figure on the following page, the top pane shows natural gas generation in Washington, most of which is served by Sumas. Note the reference line of 2,600 MW reflects maximum natural gas generation in the state. The second pane shows the peak electricity price at Mid-C for each day. The bottom pane shows the price of natural gas at Sumas.

Early in the month the natural gas fleet was producing right around 2,000 MW. However, as cold weather settled into the region during the second week of February, we saw power prices and natural gas prices move up. At a time of high electricity demand, coupled with a high electricity price signal, production from the natural gas fleet in Washington fell below 1,000 MW, which is less than 40% of the available capacity.

Figure 37: Natural Gas Constraints in the Electricity Market, February 2019



Despite the high electricity price, the high gas price made it unprofitable for plants to generate. Any available natural gas was needed to serve heating demand during the cold weather. Other sources of supply had to fill the void, and hydro was a key element of this supply.

5.4.1.2.4 Key Takeaways

- Natural gas delivery issues are real. They have happened before and will happen again.
- Natural gas delivery issues in one region can have impacts on other regions.
- Natural gas and electricity markets are inextricably linked.
- The PNW has lost 1,400 MW of coal production since the challenges in 2019.
- Other regions have lost coal and gas units. Diablo Canyon nuclear is retiring in 2025.
- PNW endured the challenges of winter 2019 due to record levels of imported electricity and coal units which are no longer available. If this chain of events were to play out again in 2022 we would not have coal supply and would be unlikely to get the same level of imports. If hydro supply were also further constrained, we would have serious issues.

5.4.2 Hydro Provides the Same Service as Gas Peakers in PNW

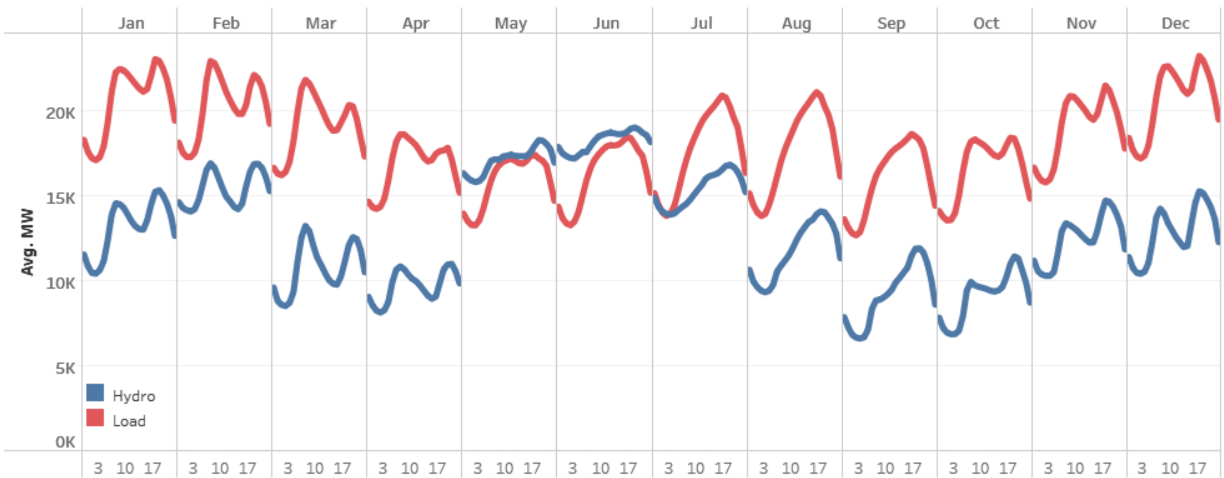
The crucial role of supplying flexible generation during times of high demand and/or scarcity that is played by gas peakers in CAISO and the Desert Southwest is filled by hydro in the Pacific

Northwest. In the PNW, hydro flows are shaped within each day to provide needed generation during high demand hours and scale back generation during hours with low demand, obviating the need for widespread gas peaker units.

The next series of figures illustrate the relationship between peak load in the PNW and hydro production.

The figure below plots the average hourly electricity load and average hourly MW of energy from hydro generation by month during the year 2020. Each pane represents an hourly demand and hydro supply profile for a "typical" day.

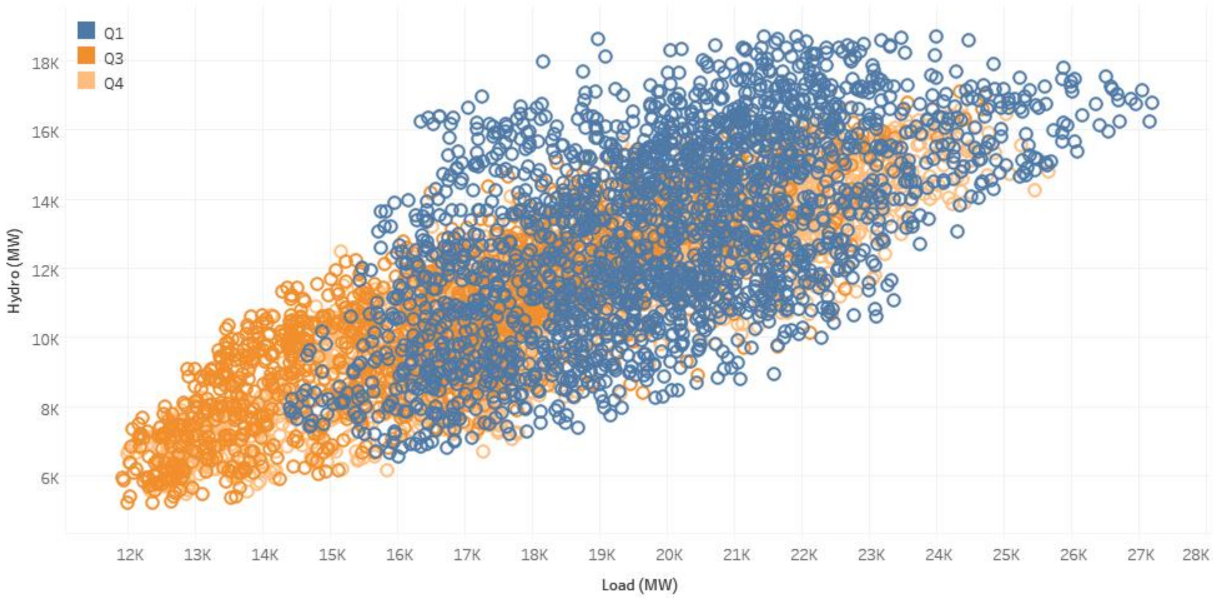
Figure 38. Average Hourly PNW Load and Hydro Generation (MW) by Month, 2020



- In January-April and August-December, hydro generation is shaped to follow the daily demand profiles, with peaks in the morning and evening ramp periods corresponding with the peaks in demand, and lows during the midday and nighttime hours corresponding to lower demand as well.
- In May and June, the pattern is muted. During the spring runoff period flows in the river are when rains and snowmelt from the mountains are at their highest and the resulting flows in the Columbia and Snake rivers are so high that shaping is unneeded and potential hydro generation is more than what is needed to balance the system.
- The figure illustrates how hourly generation patterns follow load profiles closely. On both an hour-to-hour and day-to-day basis, hydro power is used in the PNW to match load in the same way peakers are used in other regions.

The next figure plots hourly hydro generation against hourly load to illustrate how when load increases, so does hydro generation.

Figure 39. Hourly Hydro Generation by Load for the PNW



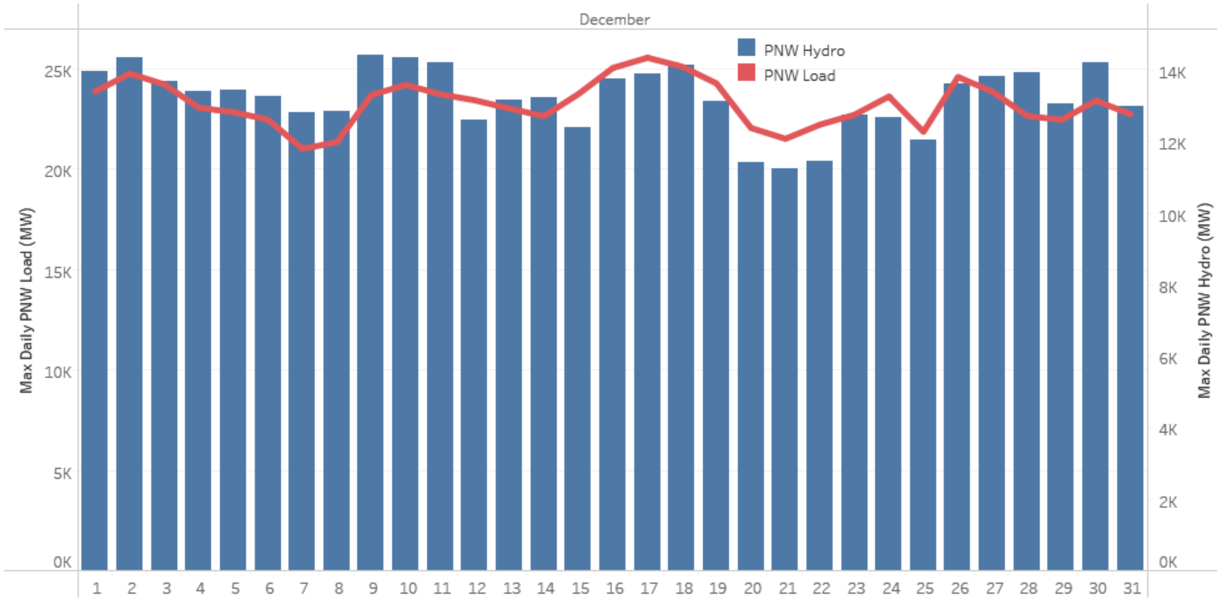
- Each circle in the figure represents a single hour from 2020, with the hydro generation (in MW) for that hour shown along the y-axis and the hourly load (in MW) shown along the x-axis.
- April, May, and June from Q2 as well as July from Q3 are excluded, as flows during these months are so high that scarcity is rarely an issue in the PNW and hydro flows remain high throughout this period even when demand is low.
- For the months included from Q1, Q3, and Q4, there is a clear positive association between load and hydro. When demand is high it is typically hydro power—and not natural gas peakers—that increases output to fill that demand.

Another way to examine the role of hydro as a peaker is to look at daily maximum values. The following figure focuses on a single winter month, showing daily data for December 2017.

- The red line depicts maximum PNW daily load and the blue bars depicts maximum daily hydro generation for each day in December of 2017. These measures are used to capture the highest levels of scarcity in each day, as well as to capturing the full impact of hydro power as flexible generation from one day to the next.
- Throughout the month, hydro generation rises and falls to match the change in peak demand. Over the first week, demand declines on each consecutive day after the 2^{nd} with hydro generation trending downwards to follow. Demand rose on the 9^{th}, then again on the 16^{th}, 23^{rd}, 26^{th}, and 30^{th}, with hydro generation increasing on each of those days.

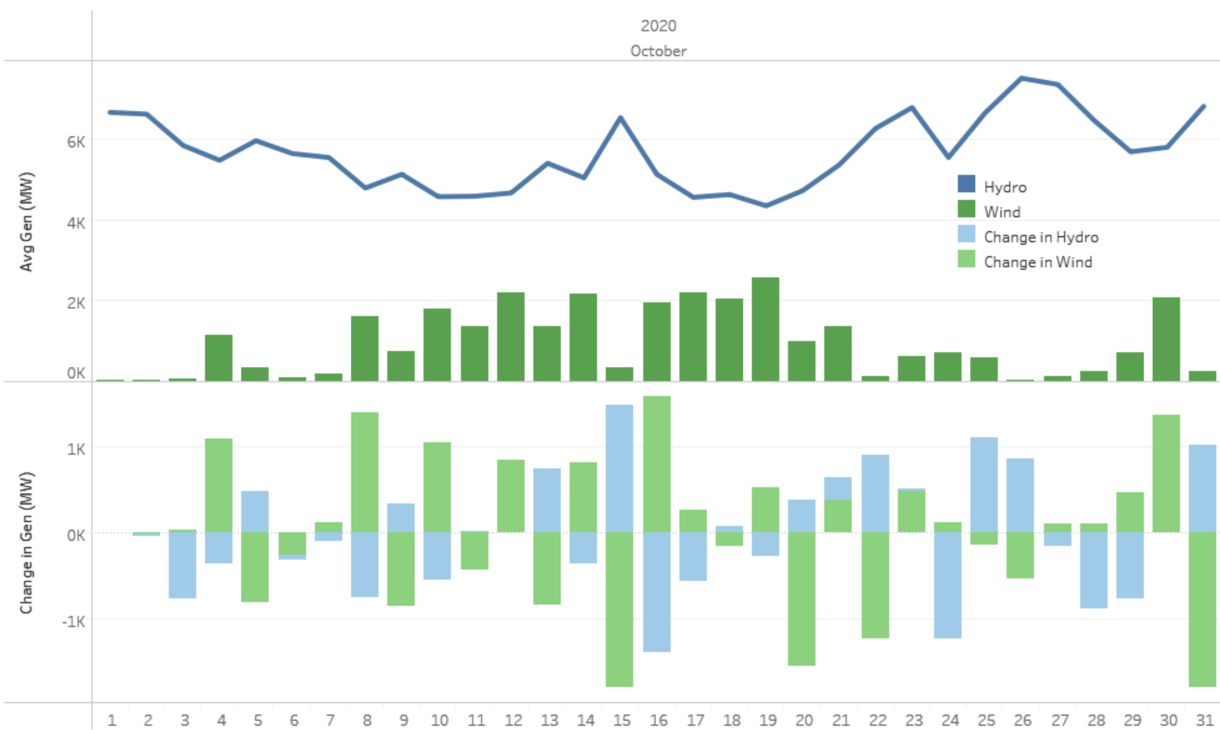
The trend is clear: maximum hydro production largely tracks maximum daily load. Days with the lowest max loads have the lowest maximum hydro and days with the highest max load have the highest maximum hydro production. Daily maximum hydro generation falls on days when peak demand is lower and rises when peak demand is higher.

Figure 40. Daily Maximum PNW Load and Hydro Generation, December 2017



In addition to tracking load, the hydro system plays a critical role in smoothing out variability in wind production. The figure below plots daily average hydro and wind in one month, October 2020, to show that on days when the wind fails to blow in the PNW and leaves a gap in the supply stack, hydro generation increases to fill that gap as needed.

Figure 41. Daily Average PNW Hydro and BPA Wind Generation, October 2020



- The top pane of the figure shows average daily PNW hydro generation during October 2020 as a blue line, with daily average BPA wind generation as green bars. Hydro tends to go down when wind goes up and vice versa.
- The bottom pane shows the day-on-day change in hydro in light blue, with the daily change in wind in light green, illustrating average daily changes (from the prior day) in wind and hydro production. The trend here is clear: when wind production goes up from the prior day, hydro production goes down. On many days, the change in hydro almost perfectly matches the change in wind. Hydro not only provides hourly shaping, it manages water flows across days to balance out changes in wind production.
- The figure illustrates the inverse relationship between hydro and wind in the Northwest. The month of October started out with very little wind, and hydro generation averaged over 6,000 MW. On the 4th some wind generation began to appear, with hydro falling. Hydro fell further on the 8th when significant wind generation showed up, lasting for one week. Hydro generation remain low until the 15th, when wind dropped off suddenly and hydro generation increased at the same time. When the wind returned on the 16th, hydro generation fell off again until the 22nd, when wind decreased.
- The light green and light blue bars move in opposite directions on almost every day. For example, on the 15th, when wind decreased from the day before the green bar is negative. On the same day the blue bar for hydro is positive, as hydro gen increased just as wind was decreasing. The following day, on the 16th, the bars are flipped, with wind increasing and hydro decreasing.

The pattern is clear and suggestive: When wind is low, hydro increases to make up for the lost supply. Hydro power is functioning just as peakers do elsewhere.

In conclusion, the figures in this section illustrate in a very real way that hydro power is the key component for balancing supply and demand within the PNW and reduces the need for combustion gas peaker plants.

5.5 Scarcity Develops in the PNW

5.5.1 Hydro History of Oversupply

The PNW electricity markets have enjoyed ample supply since the large dams were built on the Columbia River. When the Grand Coulee dam was completed in 1942, regional planners wondered whether there would ever be enough load to soak up all of the excess energy.

The dams brought economic development to the region. Most notably, aluminum smelters developed in parallel with the major dams, effectively converting electricity into high value metal and providing high wage jobs to go with it. At its peak, there were ten aluminum smelters in the region with total demand of about 4,000 MW.

In the past, aluminum smelters not only purchased the abundant energy from the dams, they also played a vital role in maintaining grid reliability. Contracts between utilities and aluminum smelters featured curtailment provisions allowing load-serving entities (e.g., BPA) to recall the electricity from the aluminum smelters at times when electricity system demand was high. In exchange for low electricity rates, aluminum smelters were willing and able to curtail their load. This structure provided an important tool in the reliability toolbox for 60 years until the smelters shut down.

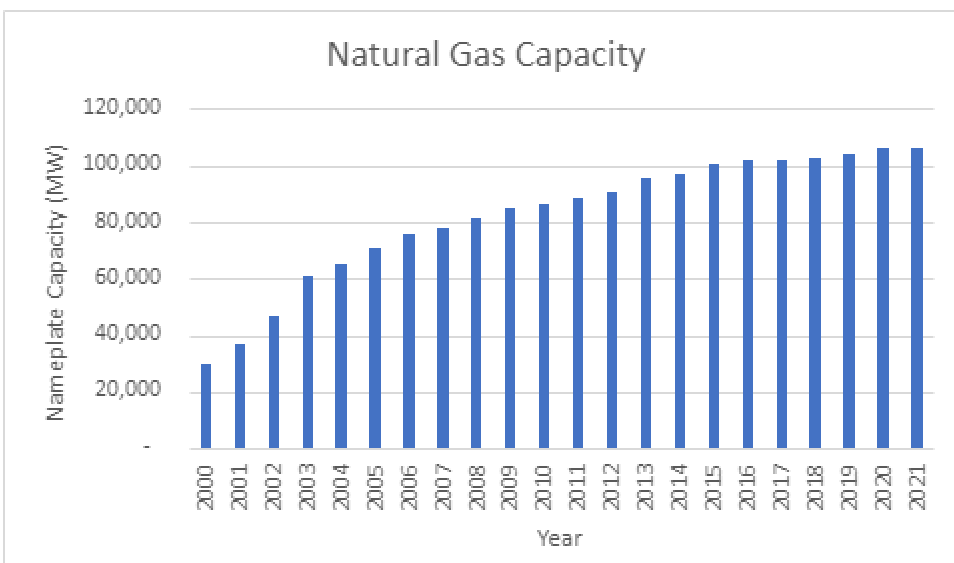
Another tool developed by BPA to address oversupply challenges was to increase regional transfer capability through transmission projects. The AC and DC interties connecting the PNW with California provided almost 8,000 MW of transfer capability between the regions. When these projects were approved in the 1970s, the thinking was that these lines would be two-way highways, where the PNW sent excess supply in the spring and summer to California and then imported energy from California in the winter.

As detailed further below, these lines have been used almost entirely to ship energy from the PNW to California. It is extremely rare for collective flows on the AC and DC interties to be northbound. It either never happened or rarely happened from the mid-1990's until 2015. Since 2016, northbound flows comprise on average 0.4% of total flows on the line. The vast majority of the MWh which have moved northbound have resulted from oversupply of solar. Only during the scarcity events of February and March of 2019 has California delivered MWh to the northwest outside of surplus solar hours.

From the 1940's until about 2020, the PNW has been short on electricity supply only once. That was during the Western Electricity Crisis of 2001, which was exacerbated by an extremely low water year in 2001. Even with the low water in 2001, the region was still able to export significant amounts of energy to California to help mitigate its blackouts. There were no blackouts in the PNW; it was California that was in desperate need.

One reason the region had excess energy was the aluminum smelters were able to shut down when prices skyrocketed. After the crisis, only three of these smelters returned to service. By 2010, all smelters had effectively shut down for good. Following the crisis, the water returned to normal, recharging the reservoirs and providing a healthier hydro system.

Figure 42: WECC Installed Natural Gas Capacity (MW)

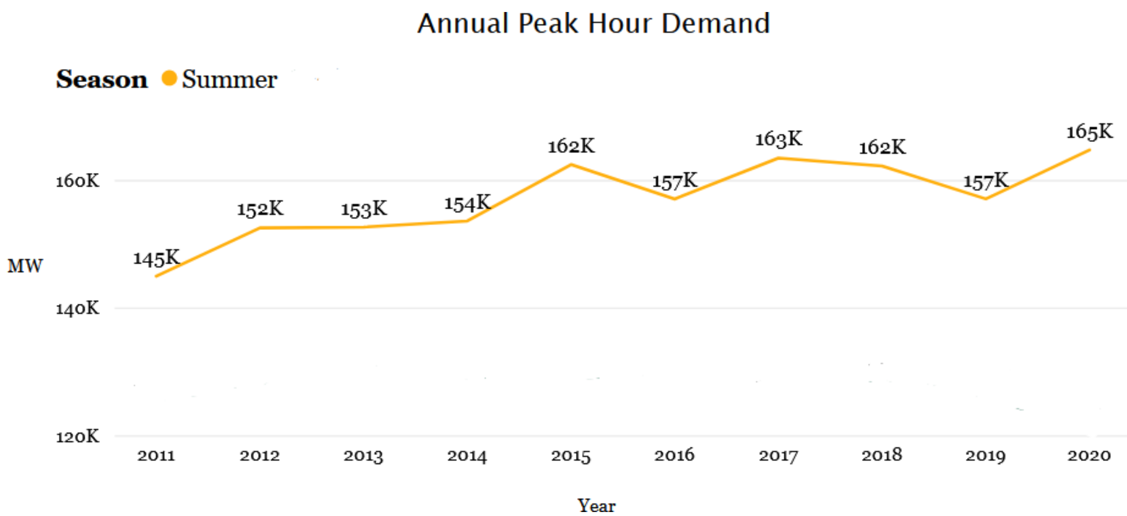


The region (and indeed the entire US) experienced a natural gas power plant building boom beginning in 2000. From 2000 until 2015 the installed natural gas generating capacity jumped from 30,000 MW to 100,000 MW – more than a 3x increase as depicted in the figure on the previous page.

5.5.2 The Markets Tighten

Over the last decade, the WECC has experienced steady growth in peak summer demand. From 2011 through 2020 annual peak demand increased from 145,000 MW to 165,000 MW – which equates to an additional 2,000 MW of firm demand each year. The figure below shows peak summer demand by year as reported by WECC.

Figure 43: Annual Peak Hour Demand in WECC (MW) [36]

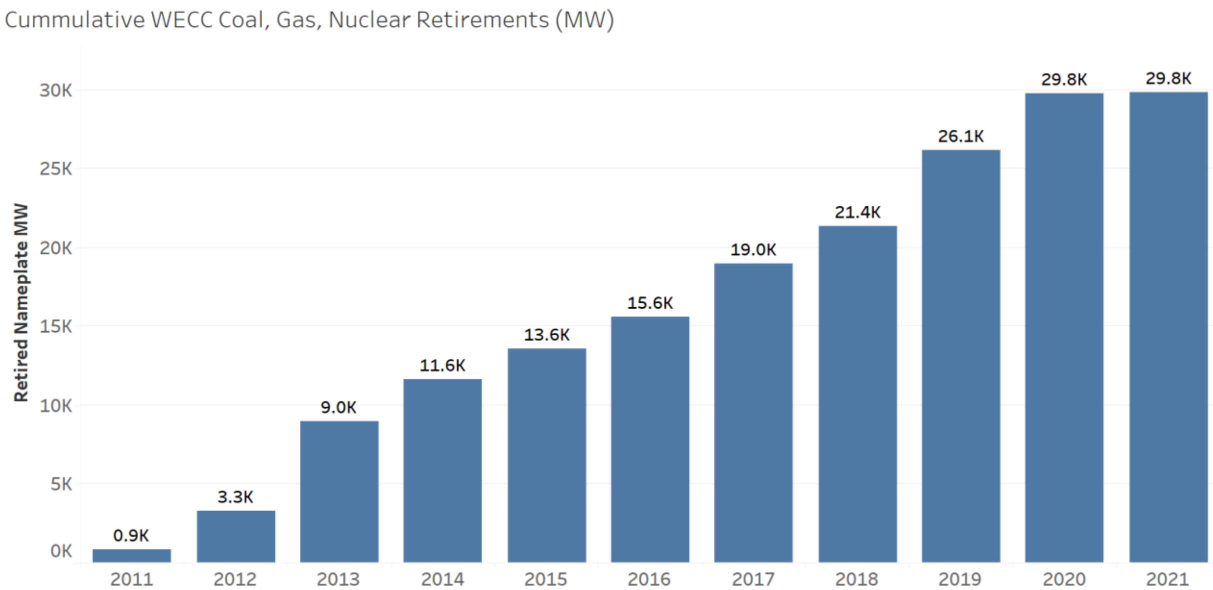


This new demand requires firm supply – it is not interruptible like the aluminum smelters were. The "new smelters" are data centers which require highly reliable power supplies and strongly prefer *not* to curtail. Yet during the last 10 years, even as demand growth gradually soaked up the excess regional supply, the WECC, including the PNW, retired 30,000 MW of coal, nuclear, and natural gas generation. The figure on the following page shows thermal retirements for the WECC from 2011 through 2021.[37]

Of the total, coal retirements comprise 11,000 MW, nuclear 2,300 MW, and old natural gas steam turbines comprise the vast majority of the remaining 16,000 MW. The WECC is in the middle stages of an energy transformation. There is a *de facto* ban on adding new natural gas generation in California, Oregon, and Washington. We are replacing thermal plants which are not energy-constrained with renewables that are energy-constrained and provide little capacity benefit. Both wind and solar pose challenges with providing reliable capacity. Scarcity in electricity markets rarely happens overnight. It creeps up over time. Even when there is scarcity, the vast majority of the hours of the year operate fine because demand is not near its peak. It is easy to ignore.

[36] https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Demand.aspx
[37] Source is EIA 860 Retirements by Month and Year. https://www.eia.gov/electricity/data/eia860m/

Figure 44: Retirements of Coal, Nuclear, and Natural Gas Plants in the WECC (MW)



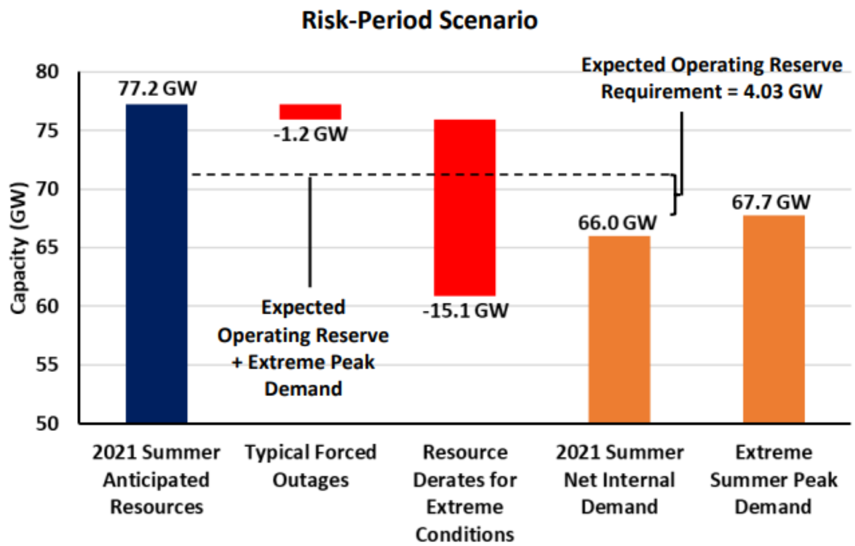
Scarcity in electricity markets manifests itself as "vulnerability". The system loses resilience and becomes increasingly vulnerable to expected but unknown challenges – low water, large thermal outages, weather events, extreme demand, and transmission outages. Vulnerability coupled with a throw-up-the-hands thinking of "oh well, accidents will happen" becomes a big problem.

There are two clear signals that the region is facing scarcity and vulnerability right now. One signal is the reliability reports published by NERC, which show lower reserve margins and greater risks of blackouts.

According to the 2021 NERC Summer Reliability Assessment, "extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption)." Translation: if the region doesn't have sufficient programmatic load reduction via utility demand response program (like the aluminum smelters used to), or if imports from other regions are not available, the region will experience rolling blackouts.

The NERC risk assessment, shown in the figure on the following page, illustrates that there are realistic current scenarios under which the PNW could wind up implementing rolling blackouts. Scarcity in the PNW is not a one-in-ten-years outlier event; it is already happening now.

Figure 45: NERC 2021 Summer Reliability Assessment for the NWPP and RMRG portion of the WECC [38]



The second signal that the PNW is facing scarcity is the wholesale price of electricity. When supply is scarce, prices increase. The figure on the following page shows the forward electricity price of electricity for Mid-C in 2023.

The sharp rise in forward prices has been in response to increases in the daily cash prices. Spot market prices have moved up significantly over the last several years. The forward price curve is indicating scarcity is in the future.

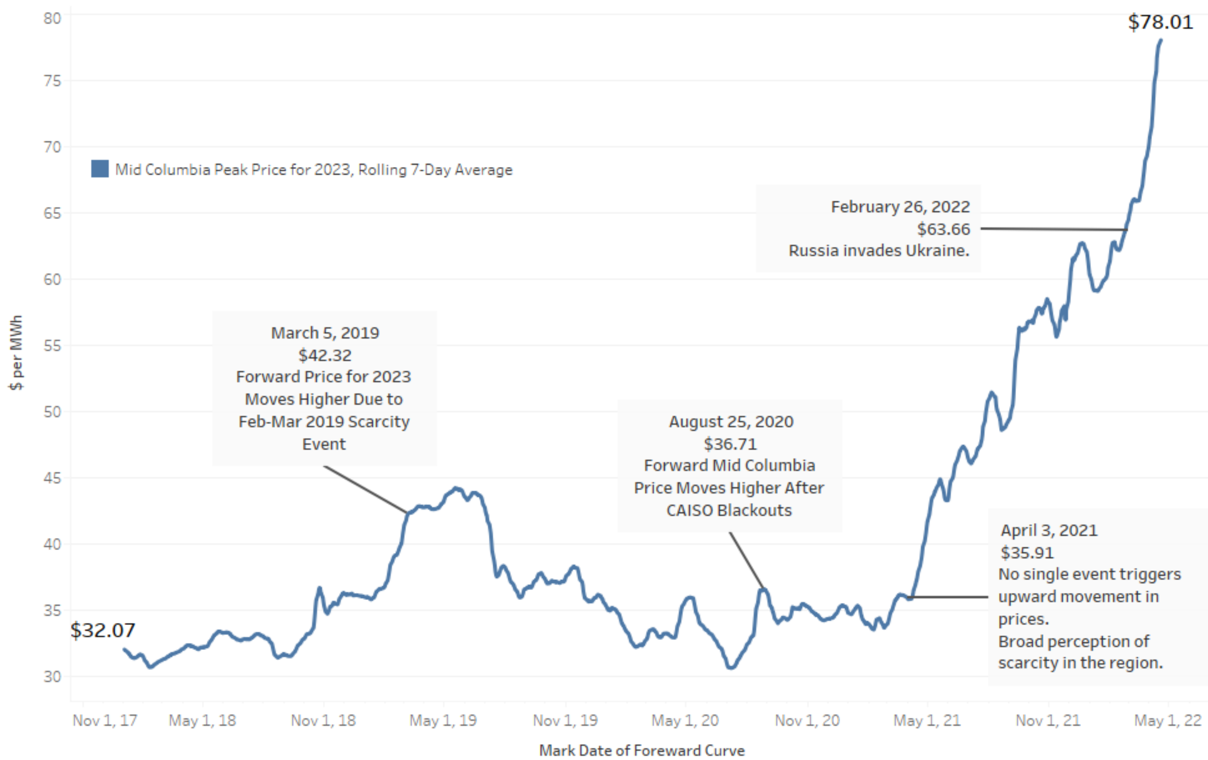
Evaluating the probability of blackouts and the impact of said blackouts on society at large is a difficult task. By nature, humans are not good at assessing low probability events with high social costs. Compounding the problem, it is difficult to know exactly how close the system is to the edge at any given time.

The utility industry uses complex, forward-looking models to estimate the probability of losing load given a set of assumptions about available generation resources, demand, and transmission transfers. Reliability is measured in units such as probability of curtailing load (blackouts) for one day in five years or one day in ten years. It is rare. It is difficult to ascertain how close to the edge the system currently is or may be in the future.

Certainly, once there are blackouts the edge comes into clear focus. But short of that, it is hard to know the dangers that may lurk just below the surface. Both NERC and electricity markets believe scarcity has arrived.

[38] Source: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf

Figure 46: Mid-C Forward Price Curve Over Time for 2023 Deliveries



In this report, EGPSC has conducted a study using actual historical data to demonstrate just how close to this dangerous edge the system has come in recent years. We use hourly generation, load, and transmission data to see what could have happened if BPA had had the reduced supply and flexibility that would result from the proposed spill rules and LSRD breach during some of these critical times in recent years.

6 Analysis: EGPSC Estimate of Lost Capacity from Proposed Policy Changes

There are two policy proposals which would reduce the supply of PNW hydro in the future: (1) the lawsuit filed by the State of Oregon in federal court which requests the court to significantly increase the spill obligations on the four Lower Snake River dams (LSRD) and the four lower Columbia dams[39], and (2) the policy proposal to remove the LSRDs.

The spill obligations for the Columbia River basin have evolved over the last twenty-five years. The incremental changes to mandatory spill requirements sought by the State of Oregon include:

- Add new spill obligations in the months of Jan-Mar, reducing the amount of capacity and energy available from these projects during peak winter demand periods.
- Extend spill obligations beyond August 14 of each year, reducing the amount of capacity and energy available from these projects during peak summer demand periods.
- Require projects to operate at minimum operating pool levels which eliminates the ability to utilize daily storage at each dam. This causes projects to effectively operate as run-of-river, "flattens" the production profile, and limits the ability to shape water and associated production into the key peak hours.

Naturally, the removal of the LSRDs would eliminate all of the generation from those projects.

6.1 Methodology: Lost Energy and Capacity from Proposed Policies

This section describes the methodology used by EGPSC to estimate the lost energy and capacity associated with these proposed policies.

The analysis begins with an hourly dataset for the 60 largest dams in the US portion of the Columbia River Basin. This dataset contains flows through turbines, flows through the spillways, metered generation, elevation levels, and dissolved gas levels for each dam impacted by the proposed policies.

The first step in the EGPSC analysis was to estimate the average MW and MWh of lost energy stemming from new spill rules. This was accomplished with a "before" and "after" analysis.

EGPSC imposed the new policy rules to the historic hourly data to create a new dataset which re-directed certain flows from turbines into spillways. In the case of LSRD removal, all production for those projects was set to 0 MW. The result is a high-quality, hourly "before" and "after" dataset which can be used to evaluate the impacts of the proposed policies.

The "before" values are actual MWh of production as published by BPA and the USACE (collectively, the "Federal Agencies"). The Federal Agencies also publish a comprehensive set of data including hourly flow by dam, expressed in thousand cubic feet per second (kcfs) including the volume of kcfs through the generating turbine or diverted around the turbines through the spillway (e.g., "spill").

For the "after" values, EGPSC calculated the turbine efficiency (h/k) and the change in generation associated with reduced flow through the turbines from the historical turbine flow and generation

[39] A description of the requested spill obligations can be found in Appendix A..

data to get spill data. From this spill data, EGPSC applied the proposed spill rules to the historical observed spill to determine the amount of additional spill required to meet the new obligations compared to the historical record.[40]

The impacts that EGPSC focused on include:

- Lost Energy: For each hour, subtracting the "after" generation from the "before" generation provides an hourly estimate of lost generation.
- Lost Capacity: The difference between the maximum "before" hour in each month and the maximum "after" hour in each month represents lost capacity for that month. EGPSC used the largest Lost Capacity value for the months of December-February as the "Winter" Lost Capacity value and the largest value for the months of July-September as the "Summer" Lost Capacity value. The annual Lost Capacity value is the average of the Winter and Summer Values.

In Section 7 of this report, EGPSC uses the estimated lost energy and capacity to calculate the short-term replacement cost of the energy and the increase in carbon emissions associated with replacing carbon-free hydroelectricity with energy from the existing fleet of generators, notably natural gas generators.

In Section 8 of this report, the lost capacity informs the discussion of reliability and scarcity events, and EGPSC explains how the loss of generation from spill and dam removal policies could impact reliability, leading to an increase in scarcity events and potentially blackouts.

6.2 Lost Energy and Capacity from Proposed Spill Rules

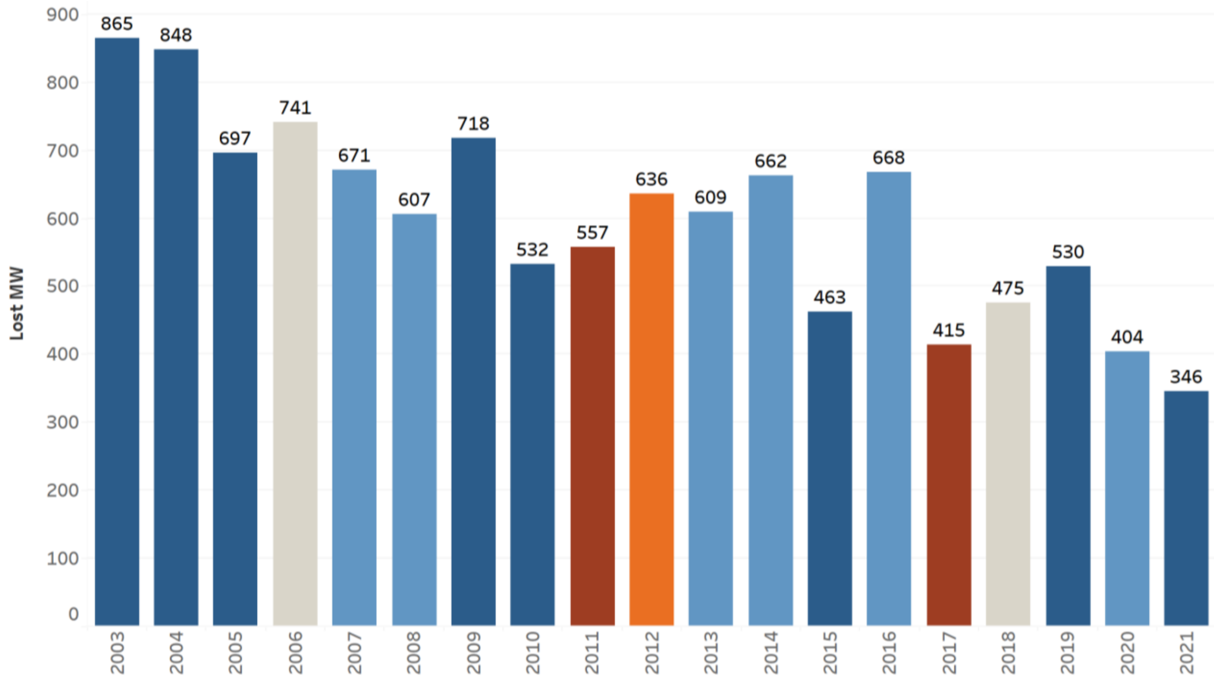
The figure on the following page shows the average MW lost by year associated with increased spill rules. The starting point for this graph is the observed production by year calculated using the EGPS 60-dam dataset. EGPS then imposes the new spill rules on the actual historical data and estimates historical production based on the proposed spill rules.

Each bar in the following figure shows the difference between the "as-observed" production data and the "EGPS estimated" production. It is important to point out that between 2000 and 2017 the spill rules have become increasingly stringent. So the value from 2000 reflects the change from the then-current spill rules in 2000 to the current proposed rules. Naturally, the impact of the new spill rules, when applied to years with much more lax spill rules, will appear to be greater than the impact in recent years. The full data series is depicted to provide a sense of scale and variability from year to year. However, for the EGPS analysis presented herein, only the data from 2017 through 2021 was used.

The figure reveals a subtle result. During low water years (dark blue bars) the lost MWh tend to be higher than during high water years (red bars).

[40] BPA provided EGPS with project operating characteristics such as minimum turbine flow, maximum spill before triggering TDG limits, and minimum operating pool for each project.

Figure 47: Average Annual Lost MW from Proposed Spill Rules



Note: the larger values earlier in the data series reflect less stringent spill rules which will naturally result in larger estimated Lost MW. The EGPS study only relied on 2017 through 2021 data.

The color of each bar reflects the average annual flows as measured at The Dalles. Red bars have higher flows, blue bars have lower flows, and the pale bars have flows close to the 14-year average. The spill rules have changed significantly over the years, with the lowest spill requirements in the early years and the most stringent spill rules in effect since 2017.

The financial, carbon, and reliability analysis in subsequent sections relies only on data from 2017 through 2021. Note that between 2017 and 2021 the Columbia River has experienced a range of flow conditions including normal, below normal, and above normal hydro years.

The proposed rules have a larger impact (in terms of lost MWh) during low water years than high water years. A key element of the proposed rules is to increase spill up until the concentration of “total dissolved gas” (TDG) below the dam reaches a certain level. While increased spill is theorized to help juvenile salmon, higher TDG levels such as those above 120% harms salmon. TDG level are largely proportional to spill amounts. In high water years, the amount of “status quo” spill is already relatively high, and the amount of additional spill that can be accommodated before reaching the TDG limit can be quite low. In low water years, it takes much more incremental spill to reach the TDG limits. As a result, the proposed spill rules have a disproportionate impact when flows, and associated generation, is already low.

Figure 48 shows the average MW of lost production by month and hour in a 12x24 graph for 2017-2021. The color shows the magnitude of the impact, with the largest impact in the spring, but still material impacts in the key winter and summer months. Across all months and hours, the average impact is 436 MW which is the equivalent a large natural gas power plant.

Figure 48: 2017-2021 Lost Average MW by Month and Hour to Proposed Spill Rules

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
1	326	314	198	612	649	483	138	187	229	166	242	283	320
2	321	308	194	602	654	479	133	184	218	157	236	276	314
3	318	311	194	597	651	477	131	184	213	157	235	275	313
4	324	319	200	606	658	495	130	186	215	161	241	280	319
5	357	342	208	566	565	444	134	189	226	185	258	303	315
6	442	400	208	720	725	484	142	199	257	250	317	387	377
7	497	425	205	880	1,063	567	151	227	339	338	388	469	462
8	505	426	197	891	1,095	587	153	229	351	356	391	476	472
9	507	424	197	837	1,054	610	152	230	356	353	390	475	465
10	503	421	207	745	963	612	162	230	365	363	379	460	451
11	483	413	210	647	896	603	163	237	376	348	343	429	429
12	453	392	216	619	861	632	164	238	388	338	320	410	420
13	437	378	217	680	978	762	168	254	395	328	308	396	443
14	430	369	219	699	965	771	173	269	406	322	303	392	445
15	433	371	218	685	979	797	178	280	413	326	303	395	450
16	465	393	219	693	992	800	183	291	419	341	331	426	464
17	502	420	219	729	1,115	822	197	302	429	365	388	467	498
18	505	424	221	843	1,337	882	209	312	435	398	431	480	542
19	507	429	221	1,025	1,551	920	205	313	447	408	443	485	582
20	505	427	218	1,064	1,540	907	202	311	445	408	438	484	582
21	505	429	218	1,032	1,432	830	196	300	447	400	431	478	561
22	493	423	219	944	1,223	758	189	284	438	364	407	470	519
23	415	381	218	708	730	543	161	218	335	269	301	380	389
24	349	336	211	642	652	509	145	191	262	198	263	315	340
Grand Total	441	386	211	753	972	657	165	244	350	304	337	404	436

Figure 49: 2017-2021 Lost Max MW by Month and Hour to Proposed Spill Rules

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
1	534	547	299	2,433	2,233	2,631	457	903	452	423	485	489	2,631
2	540	547	298	2,424	2,268	2,596	497	912	474	399	487	491	2,596
3	535	546	299	2,401	2,269	2,662	474	921	474	359	487	491	2,662
4	538	547	302	2,400	2,245	2,668	450	911	475	378	486	519	2,668
5	540	543	303	2,127	1,979	2,482	441	922	466	416	485	521	2,482
6	543	541	303	2,197	2,397	2,514	459	926	478	483	485	524	2,514
7	543	539	303	2,602	2,597	2,373	406	1,048	478	507	476	538	2,602
8	543	539	302	2,390	2,574	2,273	469	1,016	468	477	477	533	2,574
9	543	539	303	2,375	2,552	2,216	284	1,030	489	469	475	534	2,552
10	543	540	304	2,307	2,407	2,141	346	1,048	468	478	487	534	2,407
11	542	540	311	2,291	2,509	2,158	367	1,042	468	489	498	534	2,509
12	545	541	307	2,283	2,528	2,134	369	1,057	482	477	465	538	2,528
13	541	539	305	2,639	2,385	2,508	443	1,183	481	469	461	533	2,639
14	541	538	317	2,730	2,263	2,585	464	1,266	480	467	461	534	2,730
15	542	539	317	2,730	2,152	2,517	466	1,282	492	470	464	535	2,730
16	541	539	317	2,752	2,068	2,618	466	1,333	490	470	467	543	2,752
17	540	540	316	2,803	2,294	2,617	462	1,412	496	472	477	569	2,803
18	544	538	319	2,766	2,863	2,622	483	1,400	496	474	479	539	2,863
19	548	543	317	2,992	2,945	2,697	502	1,370	498	490	485	543	2,992
20	548	543	317	2,920	2,880	2,698	499	1,386	498	491	486	541	2,920
21	552	544	317	2,755	2,776	2,679	495	1,361	498	493	486	556	2,776
22	547	547	317	2,691	2,863	2,733	484	1,366	502	483	485	586	2,863
23	542	539	308	2,565	2,604	2,737	475	1,037	479	482	485	527	2,737
24	525	537	332	2,553	2,218	2,725	456	906	477	478	486	522	2,725
Grand Total	552	547	332	2,992	2,945	2,737	502	1,412	502	507	498	586	2,992

Average values (above) provide a useful measure of the average or total amount of energy lost as a result of the rule changes, but it is also useful to view the maximum possible impacts.

In Figure 49, lost "capacity" is measured using the maximum amount of lost energy in each hour within each month.

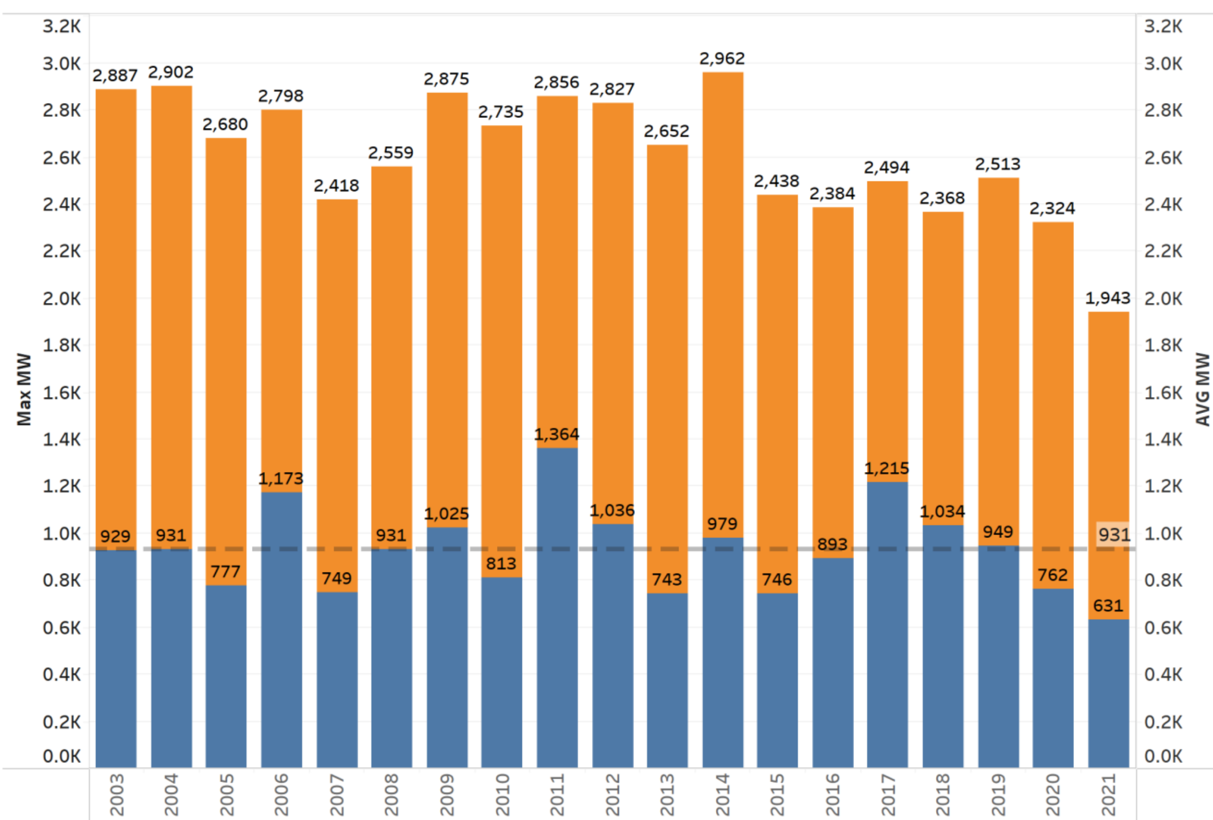
The values differ by quarter for several reasons. First, the nearly 3,000 MW of lost capacity in Q2 is because that is when the system has enough water to meet higher production levels. The lost capacity drops to 1,400 in Q3 as there is not enough water, collectively across all dams, to peak up to the same levels observed in Q2. The values are lower in Q1 and Q4 because the change in spill obligations is smaller during those months.

Nonetheless, during the critical summer months the new spill rules will result in the loss of about 1,400 MW of capacity (equivalent to three large natural gas plants or one nuclear power plant) and a loss of about 550 MW in the winter.

6.3 Lost Energy and Capacity from LSRD Removal

EGPSC used the same data set to evaluate the impact of removing the Lower Snake River dams (LSRD). The figure below shows for each year, the average MW and maximum MW for the collective LSRD projects.

Figure 50: LSRD Max Annual Output (Orange) and Avg Annual Output (Blue) MW



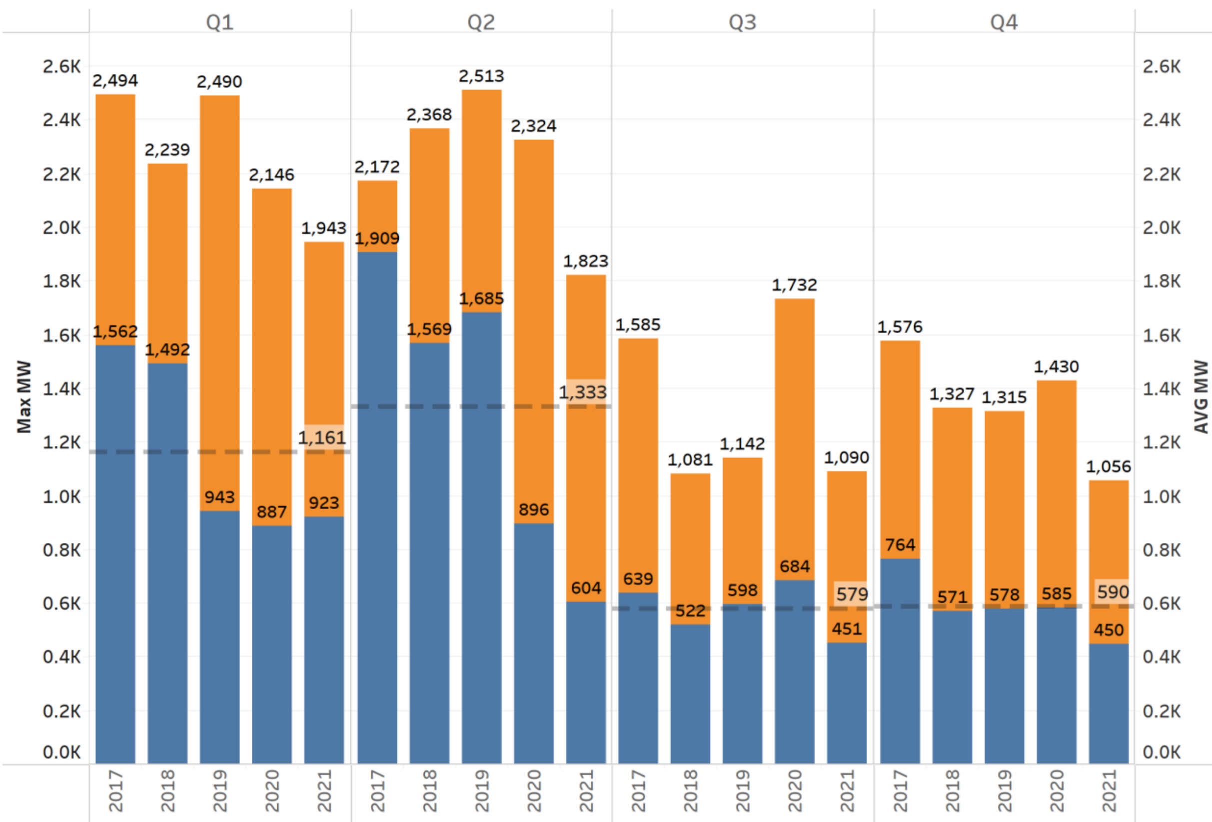
ENERGY GPS CONSULTING LLC

The orange bars show the maximum generation in each year while the blue bars show the average production for those years.

The maximum value is important because that represents how much installed capacity would exit the system and have to be replaced with equally reliable resources. The energy value shows lost energy that would be replaced with natural gas generation until renewables and storage could be developed in sufficient quantites to meet existing carbon and RPS targets as well as replace this resource.

The figure below contains another view of this same data. The figure is arranged quarterly, with each of the years 2017 through 2021 depicted for each calendar quarter in the year.

Figure 51: LSRD Max Annual Output (Orange) and Avg Annual Output (Blue) MW, Quarterly View



The LSRD complex has seasonal production profiles with Q1 and Q2 showing comparable amounts of energy (average 1,161 MW for Q1 and 1,333 MW for Q2) and comparable maximum output of around 2,500 MW. Average energy drops considerably in Q3 and Q4 as does the maximum output. This pattern of production is mostly impacted by volume of water flowing in the Snake River, however the existing spill rules also have significant impacts on March through August production.

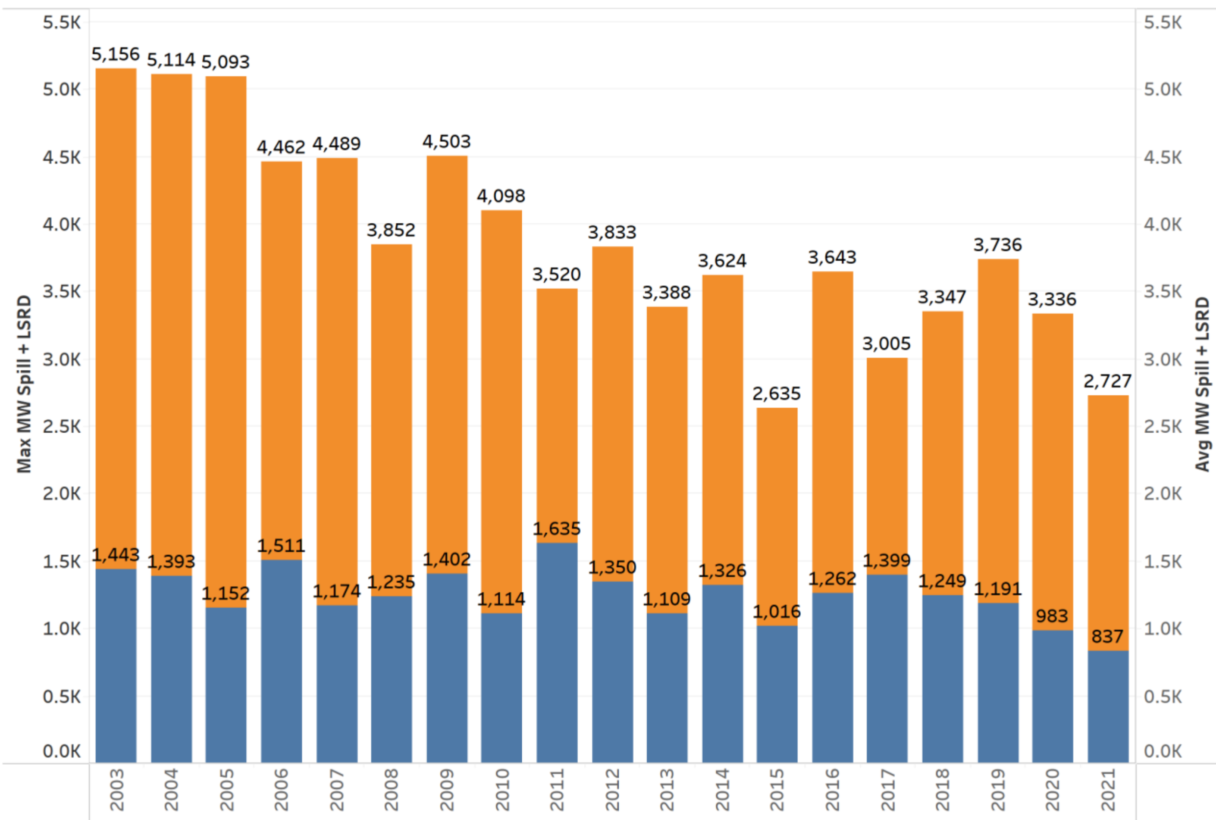
6.4 Combined Impact: Lost Energy and Capacity from Spill and LSRD Removal

It is possible that both proposed policies could be enacted: that the LSRDs are removed *and* more stringent spill rules are adopted. This section calculates the combined energy and capacity impact of these combined policies.

The analysis avoids double counting spill impacts on the LSRD that is part of the "spill only" analysis but needs to be removed from the combined impacts because there is no lost energy to spill if the dams are removed.

The figure below shows annual lost energy (blue) and maximum output (orange) which is a proxy for lost capacity, for the combined policies.

Figure 52: LSRD and Spill Impacts: Lost Max MW (Orange) and Avg MW (Blue)



The figure above depicts the lost MW from 2003 through 2021. The general downward trend over time reflects increasing spill obligations over time. In effect, from the early 2000's until the last five years, the capacity has been effectively de-rated by about 2,000 MW from 5,100+/- MW to 3,100+/- MW. Looking at 2017 through the present, the proposed policies will reduce capacity by an average of about 3,300 MW and energy by about 1,100 MW.

The following 12x24 figure depicts the maximum hourly lost production by month and hour for the years 2017 through 2021. For example, the highest lost production for hour ending 1 in January from 2017 through 2021 was 1,539 MW. This provides a useful proxy for the seasonal loss of capacity and depicts the hours when that lost capacity was deployed.

Figure 53: LSRD + Spill Impact: Max Lost MW by Month and Hour 2017 to 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
1	1,539	2,475	2,475	3,127	2,915	3,289	1,646	1,240	1,074	952	1,464	1,723	3,289
2	1,541	2,413	2,477	3,092	2,923	3,356	1,643	1,249	1,069	851	1,458	1,721	3,356
3	1,542	2,416	2,483	3,110	2,923	3,395	1,644	1,257	1,024	798	1,459	1,724	3,395
4	1,542	2,423	2,516	3,130	2,912	3,396	1,647	1,247	1,009	792	1,454	1,722	3,396
5	1,544	2,420	2,591	3,129	3,085	3,564	1,638	1,258	1,058	858	1,491	1,723	3,564
6	1,805	2,367	2,522	3,638	3,110	3,594	1,616	1,266	1,199	1,114	1,597	1,712	3,638
7	1,903	2,384	2,489	3,673	3,730	3,657	1,610	1,458	1,281	1,458	1,700	1,706	3,730
8	1,988	2,450	2,494	3,658	3,695	3,651	1,708	1,448	1,294	1,472	1,715	1,726	3,695
9	1,914	2,449	2,488	3,676	3,657	3,589	1,538	1,474	1,290	1,398	1,733	1,791	3,676
10	1,827	2,461	2,484	3,690	3,408	3,470	1,546	1,420	1,319	1,372	1,724	1,813	3,690
11	1,788	2,500	2,488	3,336	3,521	3,132	1,553	1,494	1,309	1,378	1,731	1,751	3,521
12	1,761	2,512	2,489	3,298	3,250	3,103	1,556	1,487	1,305	1,380	1,715	1,734	3,298
13	1,668	2,451	2,493	3,108	3,226	3,076	1,880	1,732	1,299	1,384	1,713	1,726	3,226
14	1,666	2,424	2,489	3,189	3,155	3,081	1,925	1,870	1,299	1,365	1,709	1,692	3,189
15	1,659	2,412	2,482	3,190	3,162	3,055	1,912	1,874	1,382	1,356	1,719	1,700	3,190
16	1,728	2,389	2,484	3,212	2,906	3,073	1,909	2,003	1,378	1,340	1,713	1,657	3,212
17	1,939	2,444	2,483	3,266	2,972	3,128	1,902	2,096	1,409	1,381	1,731	1,652	3,266
18	2,032	2,411	2,469	3,388	3,535	3,683	1,920	2,097	1,431	1,360	1,766	1,750	3,683
19	2,066	2,453	2,518	3,713	3,704	3,707	1,953	2,089	1,411	1,420	1,793	1,766	3,713
20	2,111	2,452	2,547	3,736	3,695	3,696	1,943	2,090	1,404	1,459	1,796	1,739	3,736
21	2,040	2,445	2,569	3,726	3,633	3,701	1,941	2,080	1,371	1,459	1,790	1,692	3,726
22	1,870	2,504	2,472	3,720	3,644	3,650	1,922	2,039	1,368	1,406	1,780	1,682	3,720
23	1,671	2,521	2,476	3,593	3,482	3,190	1,887	1,387	1,229	1,150	1,686	1,675	3,593
24	1,668	2,465	2,475	3,571	3,383	3,258	1,647	1,242	1,176	996	1,584	1,719	3,571
Grand Total	2,111	2,521	2,591	3,736	3,730	3,707	1,953	2,097	1,431	1,472	1,796	1,813	3,736

Note that the figure above shows that during winter scarcity events, the system may have as much as 2,500 MW less capacity, during June events the system could lose as much as 3,700 MW, and summer scarcity events may have about 2,000 MW less capacity to meet peak demand. This will be important to the discussion in Section 8, where we discuss PNW scarcity events that happened in February 2019, March 2019, and June 2021.

7 Analysis: Estimates of Increased Carbon Emissions and Short-Term Replacement Cost

This section provides estimates for the increased carbon emissions and cost to replace the lost energy and capacity from the market.

Determining the quantity of renewables and storage that will be required to replace the lost hydro capacity and energy and estimating when those replacements will be available is beyond the scope of this analysis. It is our understanding that there are several studies currently underway which will address those questions.

EGPSC's understanding is that it may take into the 2040's to build out the necessary renewable generation and transmission to meet current PNW RPS targets. Needing to replace lost hydro capacity and energy only adds to this need.

Until the replacement renewable energy and capacity resources are available, it is presumed the lost production described in the previous section will be primarily sourced from natural gas generation.

7.1 Methodology: Estimates of Increased Carbon Emissions

To estimate the increase to carbon emissions, EGPSC's analysis assumes lost energy will be replaced by natural gas generation for the foreseeable future. Efficient natural gas generation uses about 0.428 tons of carbon per MWh, and EGPSC used a value of 0.428 tons of carbon per MWh of energy replaced,[41] which approximates the emissions from an efficient natural gas generator.

At least 500 MW of natural gas generation in Oregon and Washington (10% of the fleet) was running during 90% of the hours between 2016 and 2020, which supports the assumption of natural gas as the next "marginal" resource. Replacing lost supply will come from natural gas generation in the area or imported from another area.

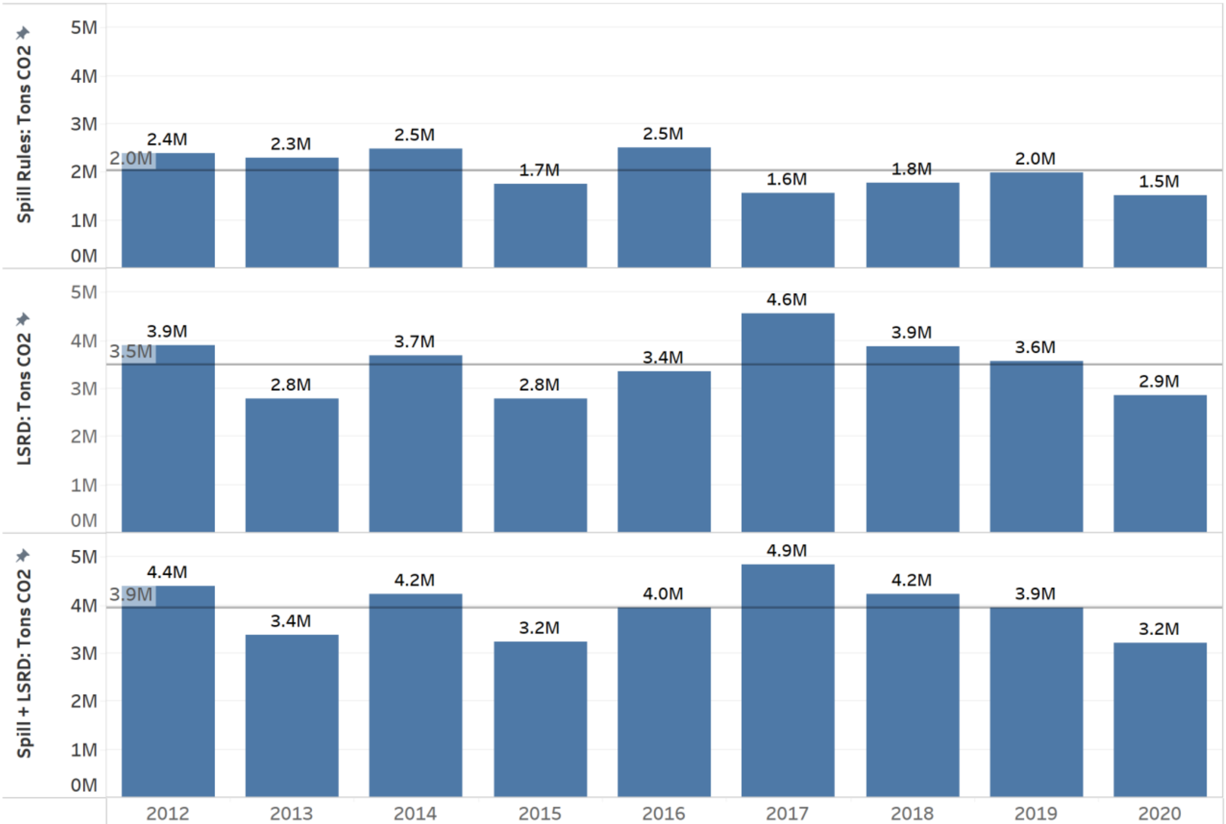
During some hours the emissions may be well above this level and during other hours emissions may be lower. To put this into context, looking at Oregon and Washington from 2016 - 2020, there were at least 1,000 MW of natural gas generation running during 85% of the hours and at least 500 MW during 90% of the hours.[42]

7.2 Estimates of Increased Carbon Emissions

The following figure shows what estimated carbon emissions would have been in previous years given the variation in river flows. This "back-cast" is intended to provide a sense for the range of potential emissions in the future should either or both of the proposed policies be enacted.

[41] The California Air Resources Board (CARB) has adopted this rate for "unspecified" imports of electricity imports into California. It approximately equals the emissions associated with an efficient combined cycle gas generator.
[42] Percentages calculated using EPA hourly emissions data. Maximum natural gas hourly output for Oregon and Washington during this time period was 5,800 MW.

Figure 54: Estimated Tons of Increased Carbon Emissions with Proposed Policies (Million Metric Tons), 2012-2020



- The top pane shows the increased CO2 emissions associated with implementing the proposed spill rules. For the period 2012 – 2020, this averaged 2 million metric tons / year.
- The middle pane shows the carbon emissions associated with replacement energy for the LSRD. For the period 2012 – 2020, this averaged 3.5 million metric tons / year.
- The bottom pane shows the combined impact of the two proposed policies. For the period 2012 – 2020, this averaged 3.9 million metric tons / year.

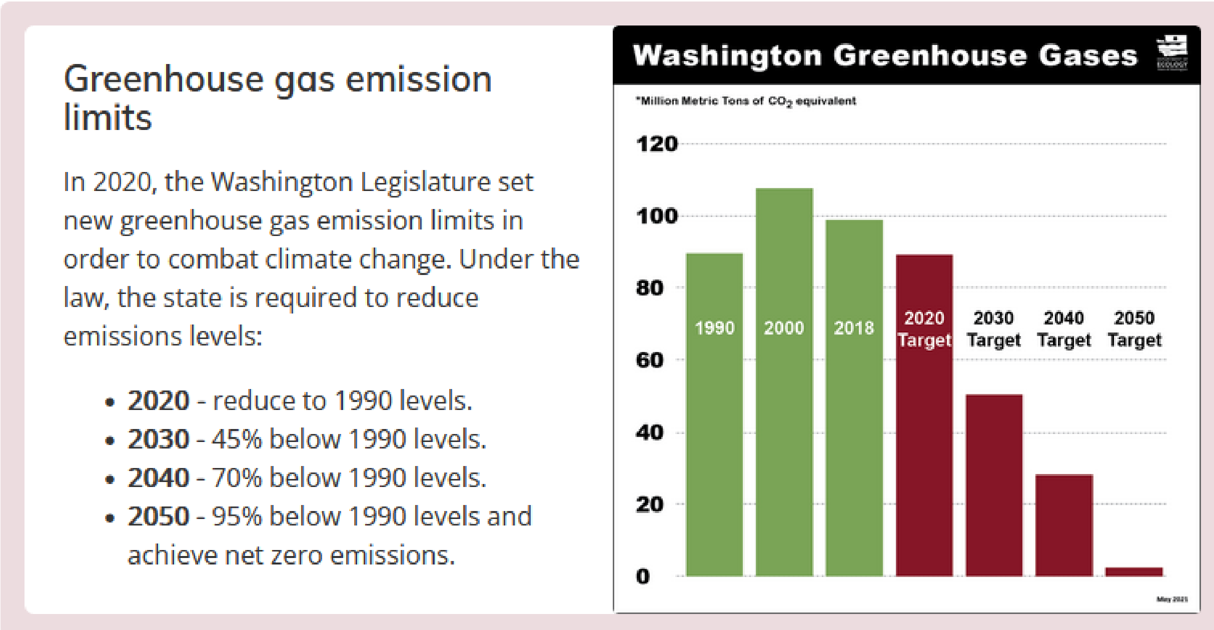
To place these estimated average emissions increases into context, we can compare this to Washington State's emission targets established by the Climate Commitment Act.[43] The figure below comes from the Department of Ecology for the State of Washington and depicts expected carbon emission limits into the future.[44]

As shown in the figure below, average increased emissions associated with reduced hydro production from combined policies (3.9 million metric tons) amount to about 8% of Washington's 2030 target (assuming 50 million metric ton target) and about 13% of the 2040 target (assuming 30 million metric ton target).

[43] https://ecology.wa.gov/About-us/Who-we-are/News/2021/Aug-6-State-begins-work-to-implement-Climate-Commi

[44] https://ecology.wa.gov/Air-Climate/Climate-change/Tracking-greenhouse-gases

Figure 55: State of Washington Carbon Emission Limits



7.3 Methodology: Short-Term Replacement Energy and Capacity Cost

This portion of the study focuses on what it would cost to replace the energy and capacity in the wholesale markets during an interim period: after the policies have been implemented and before new resources are fully built.

In the long run, the energy and capacity lost from the proposed policy changes will come from new renewable and storage resources. This study does not estimate the long-term cost of new resources.

Instead, we use 2023 as a sample year for the interim period because there is good price discovery for the cost of energy and capacity in the near-term. While the LSRD's surely won't be removed by 2023, the new spill rules could go into effect by then. We use 2023 as a convenient time period that represents what the annual costs may be once spill or LSRD removal policies go into effect to inform the debate related to cost.

EGPSC provides separate estimates for lost energy and capacity.

Short-Term Cost to Replace Lost Energy::

- Analysis assumes lost energy would be replaced with market purchases using forward electricity prices for 2023 to calculate the impacts for a sample year.[45]

[45] The study did not evaluate the long-term replacement of the lost MW and MWh. Given the magnitude of the renewable plus storage new-build requirements to meet existing clean energy and carbon policy goals, it may be well more than a decade before new replacement energy and capacity is available.

- Start with forward monthly curves for Mid-C from ICE for all months of the year. Blend the ICE peak and off-peak curves into monthly price curves that represent the average price for all hours of that month.
- Parse the monthly all-hours ICE curves into 24 hourly blocks for each month. This parsing is accomplished by examining historical hourly relationship and projecting those into the future. This step creates a series of monthly prices that have hourly detail.
- Estimate hourly lost production for each month pursuant to the techniques described in the previous section. This provides hourly 12x24 lost production matrices.
- With hourly prices and hourly production, EGPSC can multiply price times quantity to estimate the replace cost for the lost MWh.

Short-Term Cost to Replace Lost Capacity:

- Analysis uses estimated market prices for Resource Adequacy in the Western United States to value annual cost of replacement capacity.
- EGPSC used maximum hourly lost energy by month for winter months and summer months for 2017 through 2021. We then averaged these two figures to get an estimated annual average. For example, if the highest maximum lost capacity for a winter month was a value of 1,500 MW in February (for example) and 2,000 MW in August (for example) the lost capacity for that scenario would be the average of those two numbers or 1,750 MW.
- EGPSC calculated this lost capacity for each scenario.
- There are no transparent or publicly available PNW capacity prices. The Northwest Power Pool (now Western Power Pool) Resource Adequacy (RA) program is still being developed. EGPSC used broker quotes for RA prices in California for 2023 to set the capacity price.
- Capacity prices are expressed as $ per kW per month. To convert these to dollars per year you multiply $ per kW-month x 1,000 (kW to MW) and then x 12 (month to year) and then x the lost capacity MW. For example, 1,000 MW of lost capacity at a cost of $7 per kW-month = 1,000 x $7.00 x 12 = $84,000,000.

7.4 Estimates of Short-Term Replacement Energy and Capacity Cost

The following figure shows the results of the analysis of the cost to replace lost energy and capacity, and illustrates the short-term, replacement cost of energy and capacity is significant.

These costs don’t reflect any additional transmission costs associated with moving different supplies to BPA. Further, these costs don’t explicitly include carbon costs, although the Mid-C curve may reflect some expectation of carbon pricing.

Figure 56: One Year Estimated Cost of Replacing Energy and Capacity

	Units	One Year 2023 Cost Increased Spill	One Year 2023 Cost LSRD Removal	One Year 2023 Cost LSRD Spill + LSRD
Energy Value				
ICE Price All Hours	$/MWh	$66.49	$66.49	$66.49
Volume-Weighted Value	$/MWh	$58.80	$60.90	$61.21
Avg Lost MW	MW	435	919	1133
Replacement MWh	MWh	3,808,066	8,048,174	9,923,614
Replacement Energy $	$	**$223,899,194**	**$490,160,831**	**$607,414,401**
Capacity Value				
Replacement Capacity	MW	981	1750	2250
Capacity Price	$/kW-Mo	$7.00	$7.00	$7.00
Replacement Capacity $	$	**$82,404,000**	**$147,000,000**	**$189,000,000**
2023 Replacment Cost	$	**$306,303,194**	**$637,160,831**	**$796,414,401**

Replacement Capacity Estimates Based on Average of Lost Winter and Lost Summer Max MW

ICE Price All Hours Based on Forward Market Prices Published by the InterContinental Exchange (ICE)

Capacity Price Based on Recent WECC Capacity Price Quotes from Brokers

These increased costs represent either cost to BPA to replace this energy or revenue that BPA would not earn due to losing supply, which ultimately would be recovered through increased energy prices for BPA's customers, PNW businesses and residences:

- The proposed spill rules would cost $306 million per year based on 2023 forward prices.
- If the LSRDs were removed by 2023, the short-term replacement cost would be $637 million per year.
- If both the spill rules went into effect and the LSRD's were removed, the annual cost would be $796 million.

8 Application: Impacts of Less Hydro Supply During PNW Scarcity Events

In this section of the report, EGPSC explains "scarcity events" (periods of time when electricity demand exceeds available supply), discusses the supply sources available to moderate scarcity events, evaluates how demand was met in several scarcity event case studies, and analyzes what would have happened in each scarcity event if the proposed policy changes to hydro had been in place.

The case studies comprise two winter and one summer scarcity event, and a discussion of notable national scarcity events:

1. February 2019,
2. March 2019,
3. June 2021 heat dome event, and
4. Notable scarcity events experienced in other power markets, including the PJM Polar Vortex, CAISO Blackouts, and Texas Blackouts

In each of the case studies, we will tell the story of each supply resource's availability, which supply sources made the difference in moderating the scarcity event, and conduct an analysis applying the study data from the previous section about proposed policy changes to hydro (if applicable).

The first three case studies illustrate exactly how the PNW region has balanced supply and demand in the past to avoid blackouts using all available in-region thermal resources, flexible in-region hydro resources, and imports from the surrounding regions. The fourth provides useful context in regions without our hydro system.

Collectively, these four case studies highlight the interplay between the legs of the PNW supply stool. The region should fully expect one or more of the non-hydro legs of the supply stool to be compromised at a time when demand is high. If hydro production is constrained at that same time – due to dam removal or increased spill rules – EGPS cannot see where this incremental supply will come from prior to new replacement resources being sited, permitted, interconnected, built, and energized. The region should fully expect, at a minimum, an increase in the number of scarcity events with significant price spikes. And quite likely, the region will be at a significantly greater risk of blackouts.

8.1 What is a Scarcity Event?

The electricity system is designed to have sufficient supply to meet maximum demand. When everything goes right, which is the vast majority of the time, the plan works and the light switches reliably turn on. However, when demand exceeds the planners' expectations or unanticipated supply constraints hit the system, scarcity events occur. In scarcity events, prices spike and the possibility of a blackout increases.

It must be noted that quantifying "reliability" is difficult to do, but it is somewhat easier to identify when the system under strain and reliability may be compromised: this is called a "scarcity event," or "reliability event."

A useful analogy is walking on ice on a lake. Think of the volume of ice as “supply,” the weight of the person as “demand,” and breaking through the ice as a scarcity event. The amount of ice required to support a 150-pound person is different than what is required to support a 200-pound person. The quality of the ice may change throughout the day; ice that is sufficient at 7am may not be strong enough at 1pm. Importantly, the consequences of breaking through the ice can differ. Punching one foot through the ice close to shore is very different than falling through the ice in the middle of the lake.

We choose the term “scarcity event” carefully. We don’t want to over-state or under-state the risk posed to the region.

To continue the icy lake analogy, a scarcity event is a time when the ice is prone to breaking: prices spike, demand is high, and supplies are strained to meet that demand. It does not mean that the ice will break and the person will fall into a blackout. A scarcity event is a signal that the ice is thinner than one might think and/or the weight that the ice may need to support is heavier than expected.

The consequences of a scarcity event are, in many ways, determined by circumstance and luck. Do generating units trip off-line? Are wildfires limiting transmission flows? Is the natural gas pipeline delivery system experiencing disruptions? Small changes in circumstance like these are the difference between punching a foot through the ice (price spikes) versus completely falling in (blackouts).

We look at what happened during past scarcity events to prevent them in the future. One way to identify past scarcity events is to look at historical electricity prices.

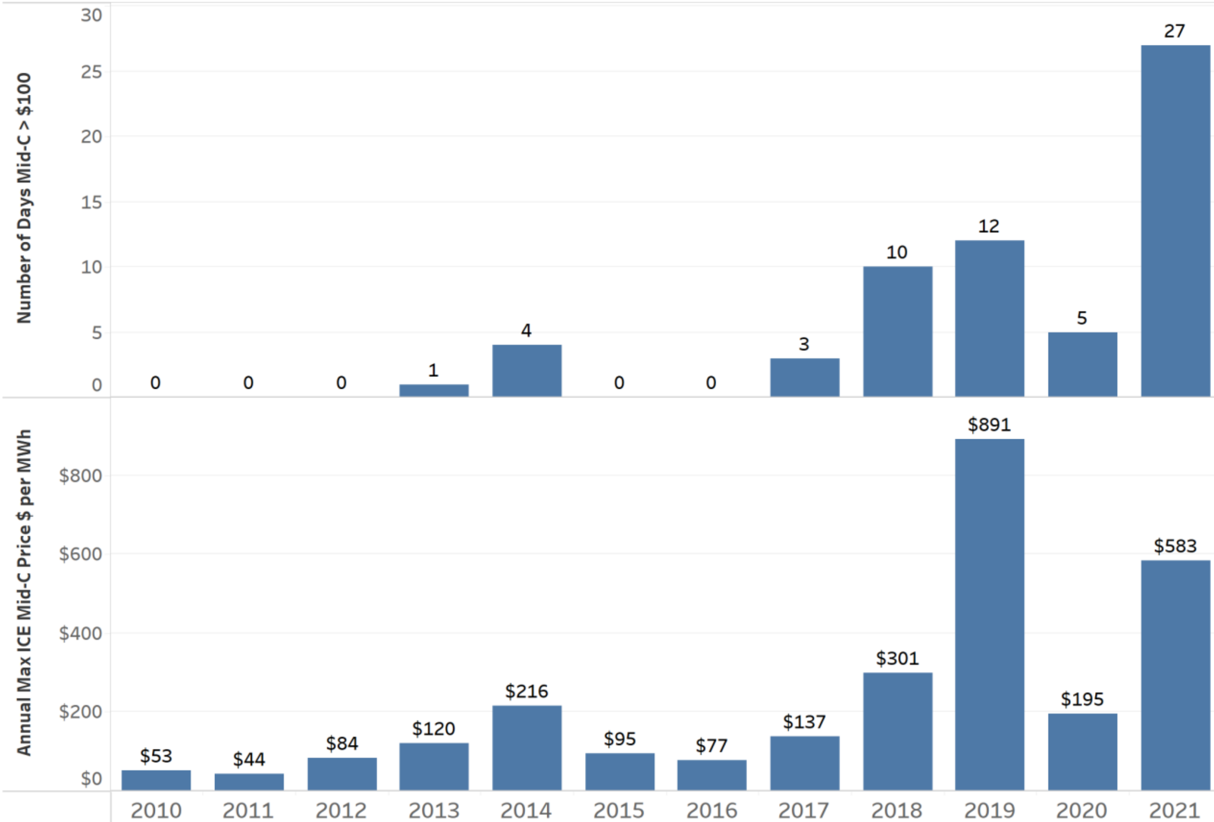
When the balance between supply and demand is tight, prices rise, often dramatically. Mid-C is the regional electricity trading hub, and the Intercontinental Exchange (ICE) reports index prices each day based on actual trades on ICE. Typically, Mid-C prices trade between $20 and $40 per MWh, depending on the level of natural gas prices, demand, and availability of hydro and renewables. EGPSC currently uses $100 per MWh as an indicator of scarcity as daily prices are more than 2x typical values.

The figure on the following page shows the number of hours in the year when ICE prices exceeded $100 per MWh (top pane) and the maximum ICE price during the year (bottom pane). It shows potential scarcity events – the number of days the price was over $100/MWh – is increasing in both frequency and magnitude.

Over the 7-year period from 2010 - 2016 there were only two years that had any scarcity events (2013 and 2014). Since 2017, there have been multiple scarcity events every year.

The number of potential scarcity events is on the rise, with 2021 experiencing 27 days with prices in excess of $100 per MWh.

Figure 57: Days Per Year When Mid-C Price > $100 and Max Annual Price, 2010-2021



Maximum prices show the magnitude of the potential scarcity event, and they have been on the rise as well, with maximum prices in 2018, 2019, and 2021 coming in well above what we've observed since the Western Energy Crisis of 2001.

8.2 Supply Used to Moderate Scarcity Events

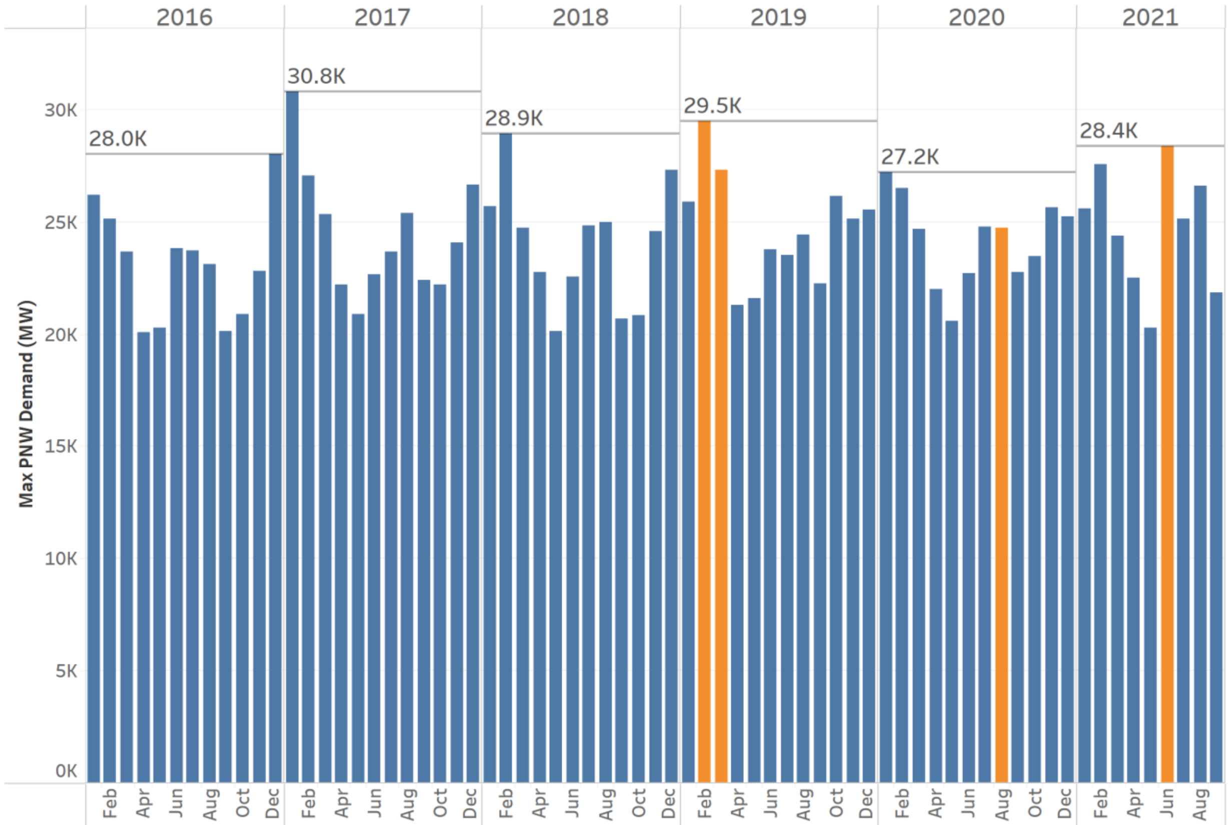
To understand scarcity events, it is important to discuss, briefly, the key components of the supply-demand balance for the PNW region.

8.2.1 Demand

The following figure shows maximum monthly values for PNW demand from January 2016 through August of 2021.

The orange highlighted bars indicate the months with scarcity events included in this section. The PNW typically sees maximum demand during the winter months. The highest demand event (which was not a scarcity event) occurred in January of 2017.

Figure 58: Maximum Monthly Demand in PNW Market Region

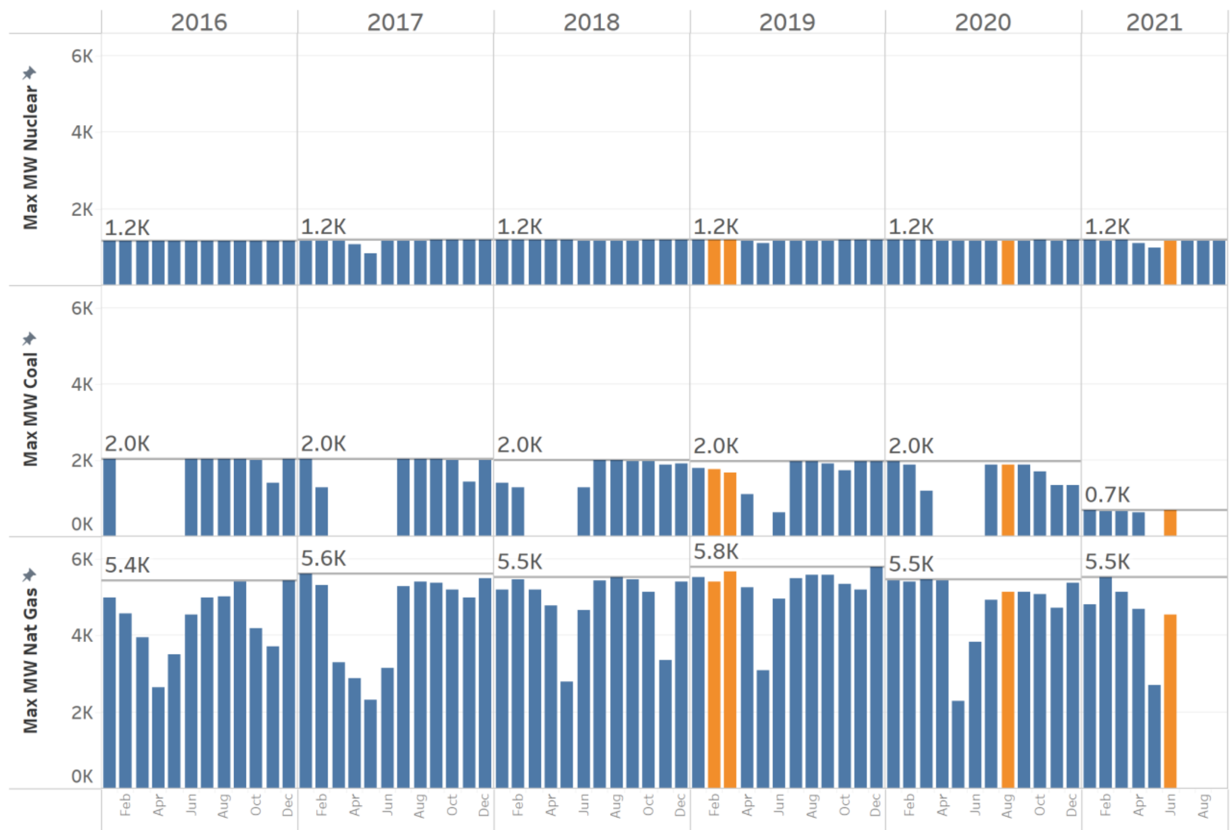


- In February of 2019 the PNW experienced a scarcity event with its second-highest demand level, 29,500 MW in Oregon and Washington.
- While demand was considerably lower in March of 2019, a fragile supply situation during that month also contributed to a scarcity event.
- The June 2021 scarcity event was triggered by the heat dome, which shattered temperature records throughout the PNW. Note that the highest level of demand in 2021 was during the June heat dome event which came in a full 4,500 MW higher than the next-highest demand in June.
- The scarcity event in August 2020 relates to the blackouts in California which was a time when PNW demand was high but not extraordinary.

8.2.2 Thermal

Turning now to the regional sources of supply, the figure below shows maximum output by month for nuclear, coal, and natural gas resources in the PNW. The same color coding is used where orange indicates the months of the scarcity event case studies.

Figure 59: Maximum Monthly Supply for Thermal Resources in PNW Market Area



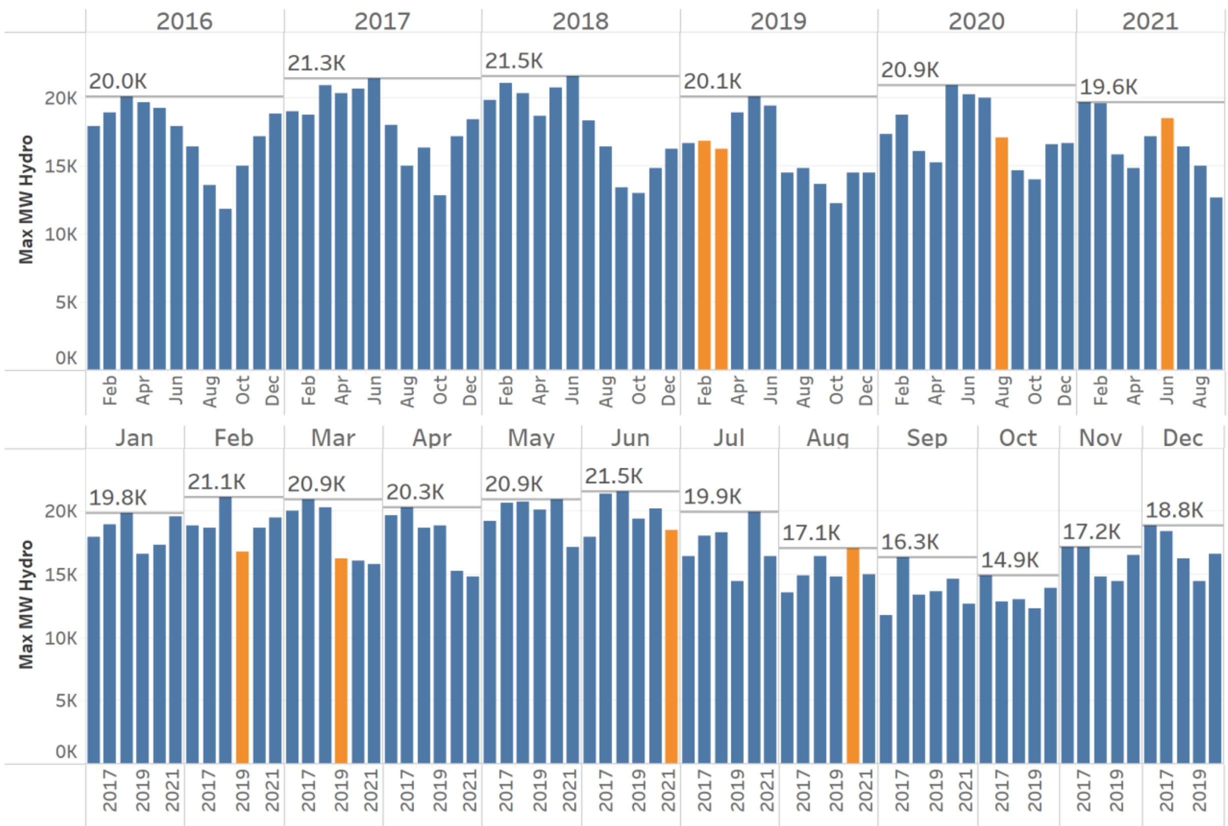
The generating resources depicted here are all located within the Oregon and Washington PNW market area.

- The top pane shows nuclear, which is the Columbia Generating Station nuclear power plant. It has a nameplate capacity of 1,200 MW and is able to produce that amount during almost all months.
- The next pane shows coal resources, which include Centralia and Boardman. Beginning in 2021 the maximum output declined from 2,000 MW to 700 MW due to retiring a portion of the Centralia project and the entire Boardman project. Scarcity events in the future won't have the benefit of as much PNW coal.
- The bottom pane shows the combined maximum output of Oregon and Washington natural gas plants. These units produce at or close to 5,500 MW each year. Note that the highest production in the record is 5,800 MW.
- The month-to-month variability of natural gas and coal production will be largely determined by price levels: natural gas plants are the most expensive resources to dispatch and are therefore the last to turn on to meet demand. During periods of low demand or high renewable/hydro output, the less efficient natural gas plants will turn off.

8.2.3 Hydro

The next figure shows maximum hydro output for the 60 largest hydro dams, representing 92% of installed hydro capacity, in the US portion of the Columbia River basin.

Figure 60: Maximum Monthly Hydro Production, Chronologically and by Calendar Month



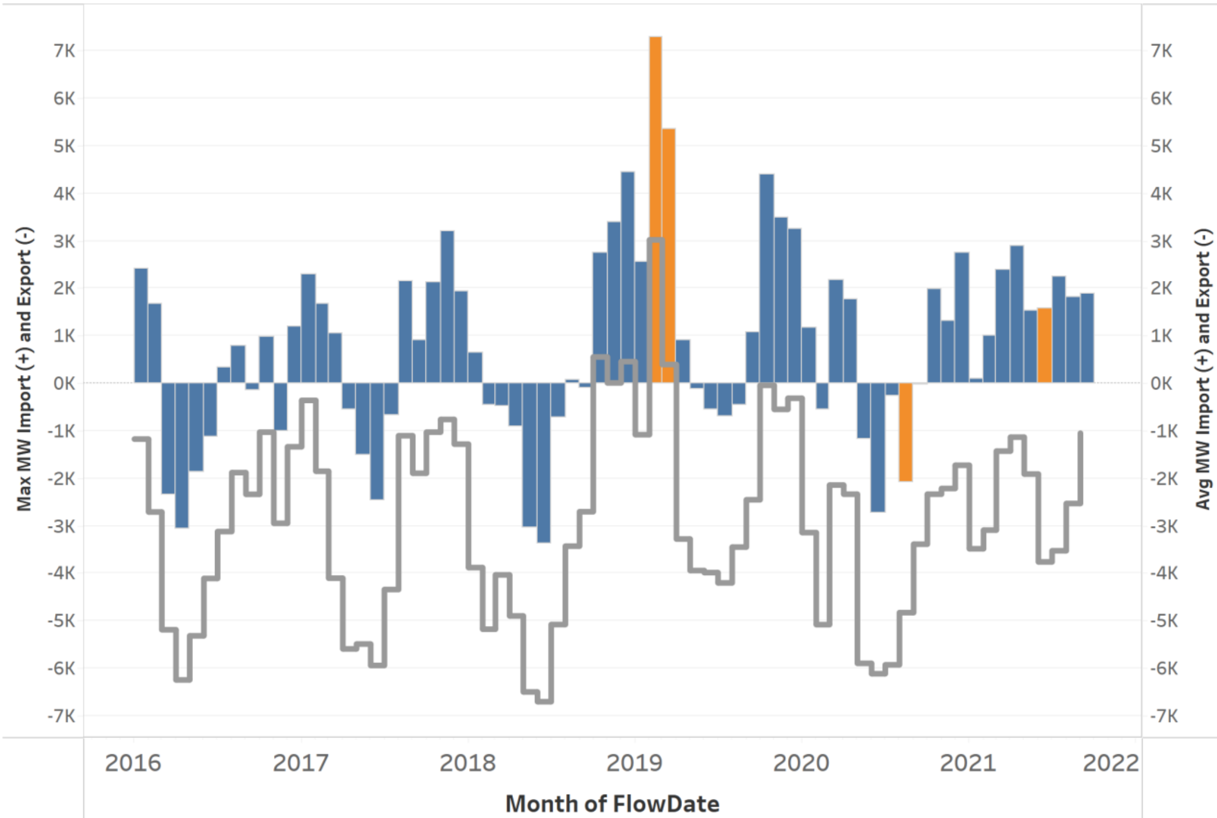
The top pane and bottom pane contain the same information but sorted differently. The top pane is sorted in chronological order, first by year and then by month. The bottom pane is sorted first by month and then by year within each month grouping.

Maximum hydro production varies considerably by month and by year. The variation depends on the amount of runoff, the timing of runoff, unit outages, dam elevation levels, and timing of flows across a wide geographic area. Maximum production is typically during the spring runoff months of March-June. There are always exceptions, for example 2021 was a low water year and the maximum output occurred in January.

Looking at the bottom pane, it is clear that scarcity events often occur when maximum hydro production is well below what is typical for that month. This was very much the case for the February and March events, as evidenced by the orange bars on the bottom pane. Hydro was also relatively low for a June during the June 2021 heat dome. As we will see in the case studies below, the hydro system demonstrates considerable short-term flexibility to meet surging demand during scarcity events, even if low levels of hydro supply are a major factor in the creation of scarcity events.

The next figure shows imports (positive values) and exports (negative values) by month. The bars depict the maximum values by month and the gray lines show the average values by month.

Figure 61: Maximum and Average Imports (+) / Exports (-) by Month



The transmission flows depicted in this figure reflect the PNW net, accounting for flows on the BC Intertie, the East side, and California interties. We show the maximum and average because these values are so different: In most months, the PNW is a net exporter as evidenced by the gray lines; however, during many months there are at least some hours where the PNW region imports energy.

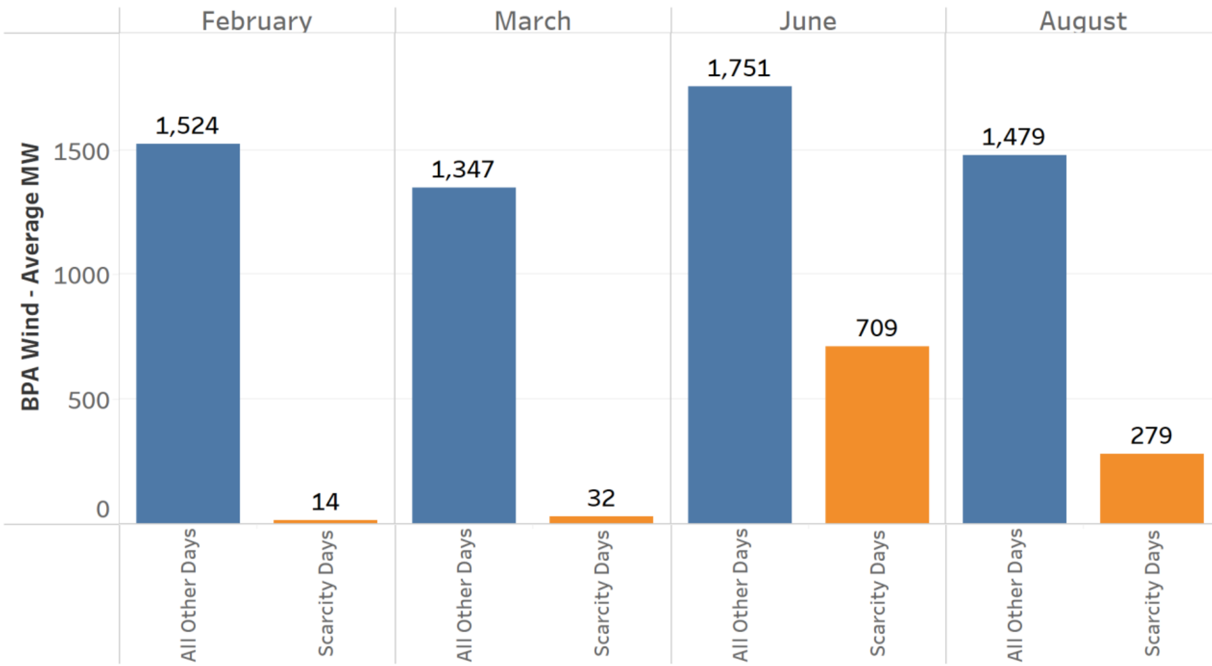
Of note is the scale of the maximum imports in February and March of 2019, reaching more than 7,200 MW in February of 2019. While the imports during scarcity events will be more fully detailed in the case studies below, this figure shows just how exceptional the February and March of 2019 net imports were.

8.2.4 Renewables

The largest renewable resource (other than hydro) in the PNW is utility-scale wind. There is no single data source which provides hourly wind production for the 10+ balancing authorities located within the PNW. However, BPA provides hourly data on wind and solar production in its balancing area. Installed wind within the BPA balancing area reached 4,750 MW by the end of 2014. Since then, about 2,000 MW left the BPA balancing authority, and the current level of wind installed in the BPA balancing authority is about 3,000 MW.

While there will be some diversity of wind resources within Oregon and Washington, the wind within BPA is an excellent proxy for the overall wind resource in the PNW footprint. The figure below compares average wind production within the BPA balancing authority during days with scarcity events and all other days within each month for the time period covering 2016 through 2021.[46]

Figure 62: Comparison of BPA Wind Production: Scarcity Events Versus Monthly Averages, Covering 2016 - 2021



These results demonstrate the limitations of the PNW wind resource. Across the four scarcity events, wind production was just 15.5% of the average production for the relevant months.

With installed wind capacity during this time of approximately 3,000 MW, the wind provided an average of 258 MW or about 8.6% of its maximum potential capacity, which is called the "nameplate capacity." On its worst day in February of 2019, wind output averaged only 0.5% of nameplate capacity. Certainly, a more diverse portfolio of renewable resources which includes wind and solar across a broader geographic footprint will help. However, solar provides little benefit during winter scarcity events where the acute need is in the morning and evening hours in dark northern latitudes.[47]

The addition of wind from Montana and Wyoming would also help. The Western Power Pool ("WPP", formerly the Northwest Power Pool) is embarking on a Resource Adequacy Program.[48] As part of this effort, the WPP is calculating a reliable capacity rating for each type of renewable

[46] Installed BPA wind capacity declined by 2000MW during 2017 and 2018. The amount of wind resource changes each year. This figure presents data for all years. If the dataset is limited to 2019-2021, results do not materially change. The "All Other Days" bars become 1,673 (Feb), 1,276 (Mar), 1,766 (Jun), and 1,626 (Aug). Because the time period selection does not systematically bias the results, EGPSC opted to display the longer time period.
[47] BPA currently has 140 MW of solar installed, so there is not a good long, term hourly record. The August 2020 blackouts in CAISO occurred between 6pm and 7pm as the solar resource was rapidly declining.
[48] https://www.westernpowerpool.org/about/workgroups/12

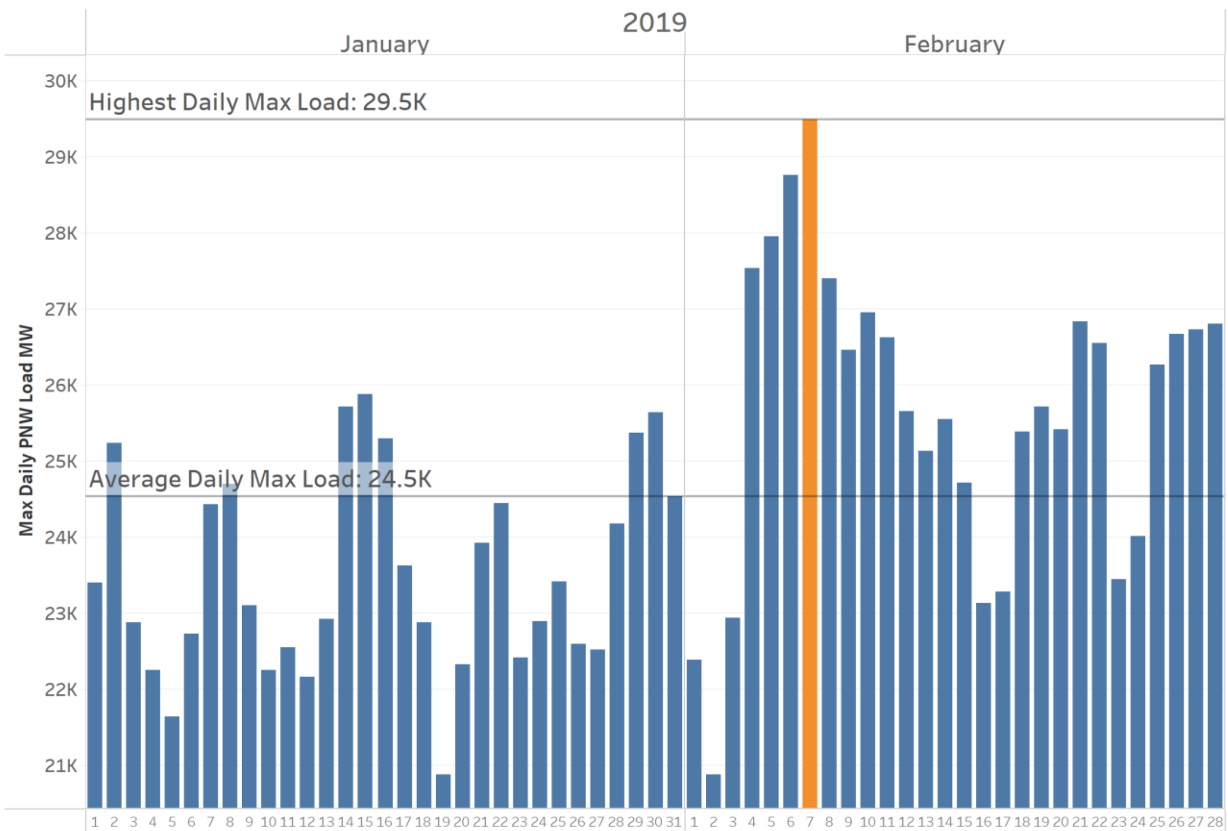
resource across five distinct geographic zones. The percentage of nameplate capacity that may count toward resource adequacy obligations has not yet been released. While the ratings for some regions will likely be higher than the results presented here for BPA, they will still be relatively modest percentages of nameplate.

8.3 Case Study 1: February 2019

In early February 2019, a cold snap hit the PNW region. By February 7, temperatures in Seattle and Portland dipped into the low 20's while temperatures in Spokane and east of the Cascades approached zero degrees Fahrenheit.

The figure below shows maximum PNW electricity demand (in MW) for each day in January and February of 2019.

Figure 63: Maximum Daily PNW Load for Jan and Feb 2019



To put this into context, February 7, 2019 was the second-highest PNW demand on record and a full 5,000 MW higher than the typical maximum winter demand in January and February of 2019. As demand increased, natural gas prices at Sumas spiked from $3.40 per to $48.70 per MMBtu. Electricity prices at Mid-C climbed from $36 to $138 and then to $218 per MWh between February 2 and February 11.

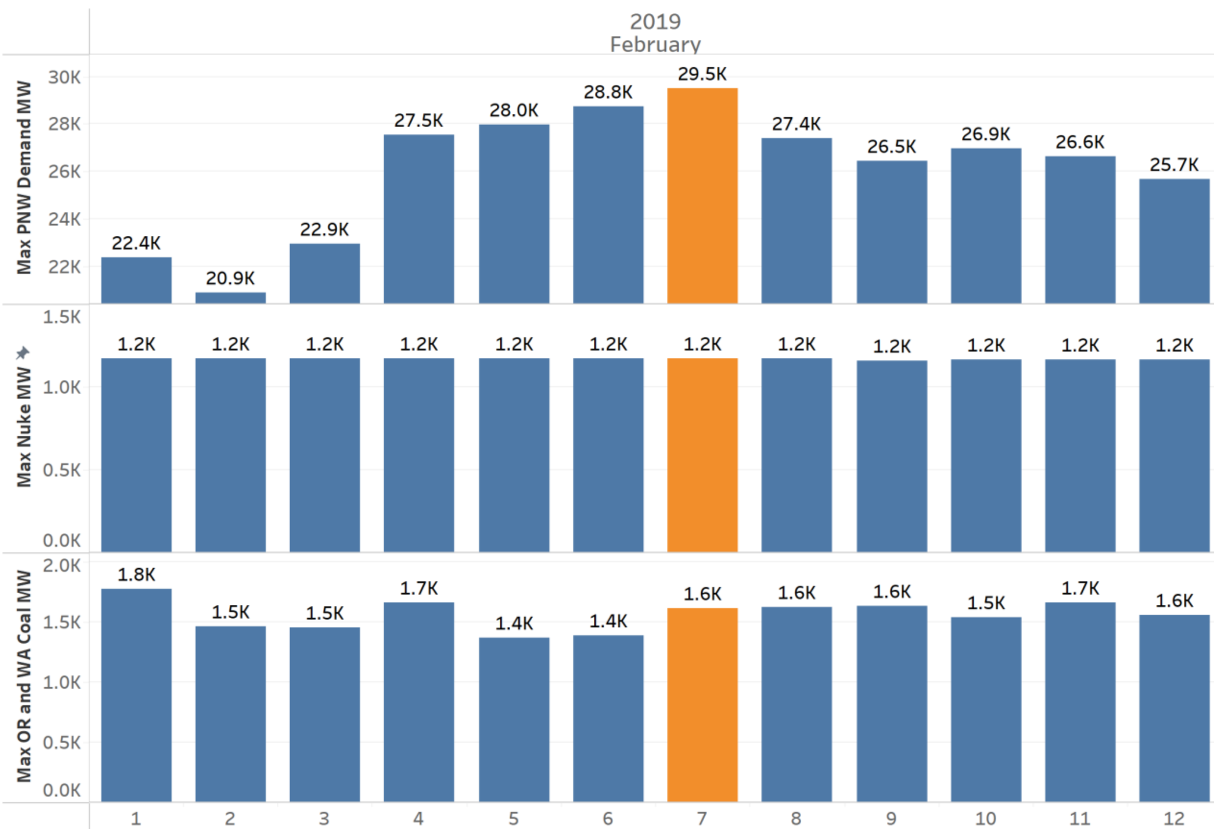
The supply stack within the PNW at the time included nuclear, coal, natural gas in Washington served by Sumas, and natural gas in Oregon served from the Rockies via the Northwest pipeline or from Canada via Kingsgate.

The series of figures below depict how the within-region resource stack responded to the higher loads. Each figure shows maximum hourly production for each day from February 1 - 12.

8.3.1 Baseload: Nuclear and Coal Fleet Provide Expected Levels of Baseload Power

We start with the nuclear and coal fleet with the figure below. This figure also shows daily data with maximum output from each resource category with nuclear in the middle pane and coal in the bottom pane.

Figure 64: Maximum Daily Demand, Nuclear and Coal Output



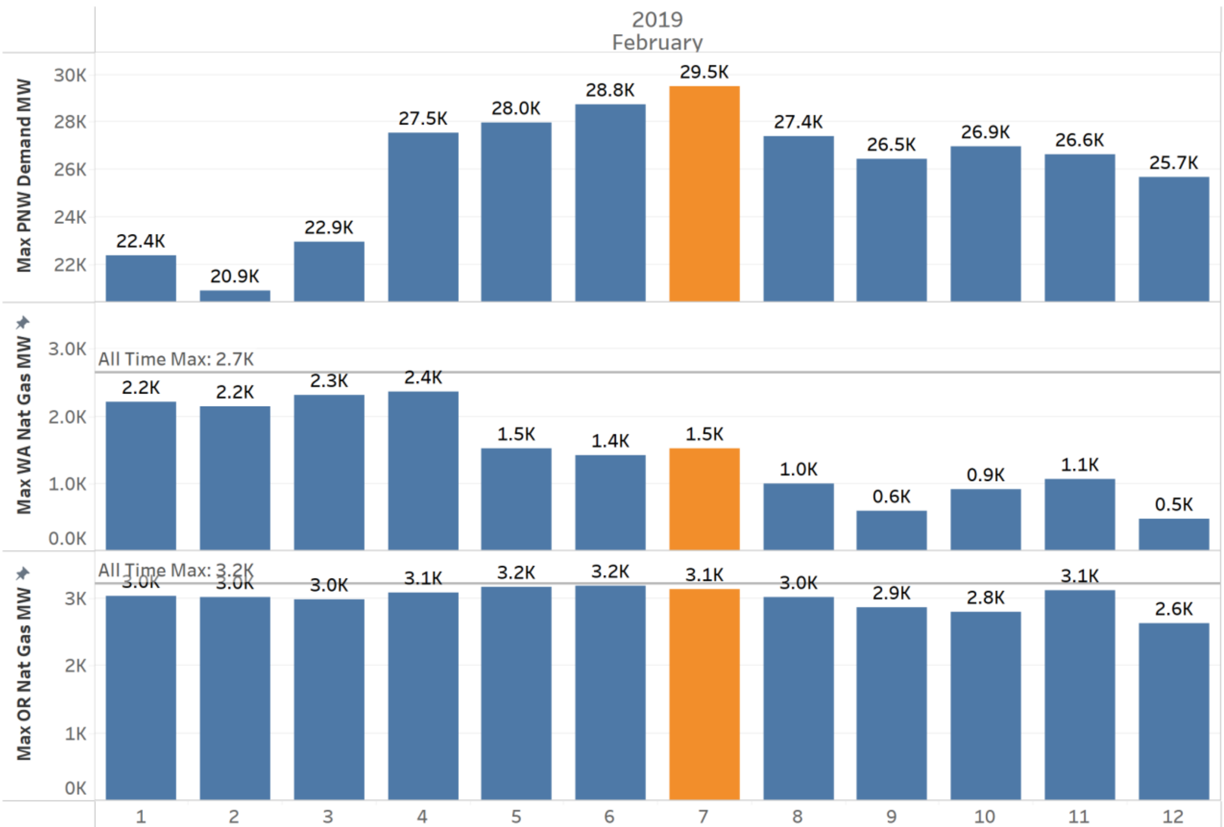
These are baseload resources with on-site fuel. The Columbia Generating Station nuclear plant performed at full capacity during this time. The coal plants included at the time Centralia in Washington and Boardman in Oregon. The nuclear unit delivered its full output of 1,200 MW during the scarcity event. Both coal units delivered just below their maximum available output during the scarcity event in what looks like short-duration, partial outages during this period.

8.3.2 Thermal: Washington Natural Gas Curtailed Due to Limited Supply

We next turn our attention to the natural gas fleet within the PNW region.

The figure below also shows daily maximums for Feburary 1 - 12. The second pane shows Washington natural gas plants, the third pane shows Oregon natural gas plants.

Figure 65: Maximum Daily Demand, Natural Gas Output in Washington and Oregon

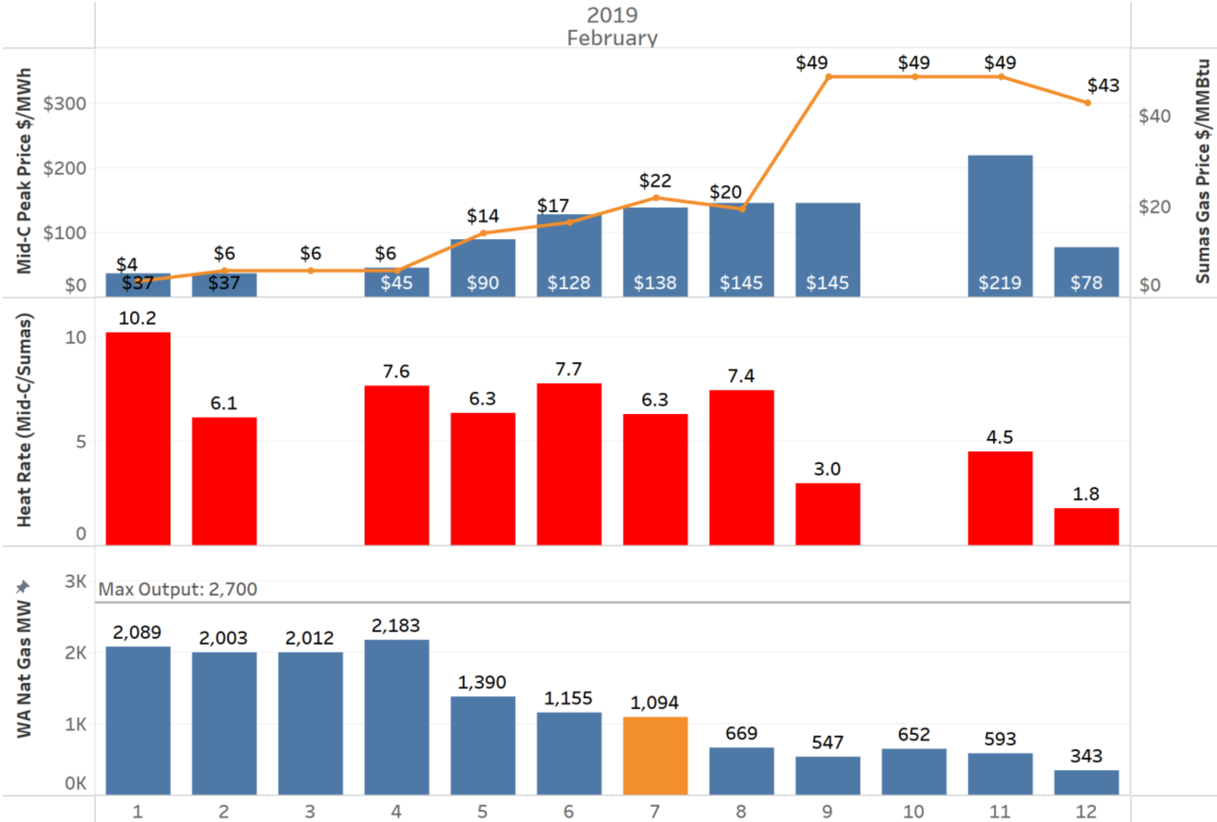


The Washington natural gas plants were only able to generate 1,500 MW, which is 1,200 MW below the maximum potential of 2,700 MW from these units. The Oregon natural gas fleet hit an all-time record output of 3,200 MW that week, and on the 7th the fleet was within 100 MW of that record.

Note that as the weather started to get colder on the 3rd and 4th of February, natural gas generation in Washington remained high, putting out close to its maximum production of 2,600 MW. However, as the weather continued to get colder, demand for both electricity and natural gas heating increased.

Although the Washington natural gas fleet was likely physically able to produce energy, the output declined. The reason for this is that gas was being rationed – via price – away from the electricity sector and to heating demand. The figure below explains how this works.

Figure 66: Prices, Implied Heat Rates, and WA Gas Dispatch



The figure tells a very logical story that connects the price of natural gas, the price of electricity and the resulting dispatch of gas units in Washington:

- The top pane shows Mid-C electricity prices (blue bars) and Sumas natural gas prices (orange line). Note that the scale of the electricity prices are exactly 7x those of the natural gas prices. An efficient natural gas plant requires about 7 MMBtu to generate 1 MWh of electricity. This conversion efficiency (7 to 1) is known as the “heat rate.” When electricty prices are more than 7x natural gas prices then efficient natural gas generators can run at a a profit. When electricity prices are less than 7x natural gas prices, then there are no gas generators that can profitably run. When the orange line is at or below the blue bar, then efficient gas generators are “in-the-money” for that day.
- The second pane depicts what is known as the “market” or “implied” heat rate which is simply the Mid-C electricity price divided by the Sumas natural gas price. The same logic holds: when the implied heat rate is 7x or greater then efficient natural gas plants can run at a profit. Notice how the implied heat rate is 10.2 on February 1 and falls to 1.8 by February 12.
- The bottom pane shows natural gas generation in Washington. As natural gas prices rise relative to electricity prices, the implied heat rates decline and the most of the natural gas units no longer generate power. This decline is not an accident. Electricity and natural gas markets use price to ration supply.

The figures show that early in the month, the natural gas plants were all running, as the implied heat rates were sufficently high for a gas plant to profitably operate. (Note that February 2 and 3 fall on a weekend, and the units likely commited to be online for the entire weekend.)

But by February 7, the region had lost almost 1,000 MW of Washington natural gas production because it could no longer profitably run them. Between February 9 - 12, the gas units' maximum output was between 500 MW and 1,000 MW. Compared to the beginning of the month, the system lost between 1,500 MW and 2,000 MW of Washington gas supply. Any units that continued to run were likely running at a loss.

The natural gas supply system NEEDED the power generators to turn off so that sufficient natural gas remained to deliver to heating customers. With the weather still cold, demand for natural gas was still strong. Further, the in-state natural gas storage facility at Jackson Prairie was quickly draining, and with plenty of winter still to come, there were concerns about adequate gas supply later in February and March. So the gas price had to rise to the point where electricity generators were willing to turn off – and that happens when power prices are less than 7x natural gas prices.

8.3.3 Hydro: Hydro Production Increases to Meet Demand As Gas Declines

Let's now take a look at hydro production during this same period. This is the most critical piece of the generation fleet within the PNW market.

The figure on the folllowing page shows average monthly hydro production for each February from 2016 - 2021 (top pane) and maximum daily hydro production for each of the first 12 days of February 2019.

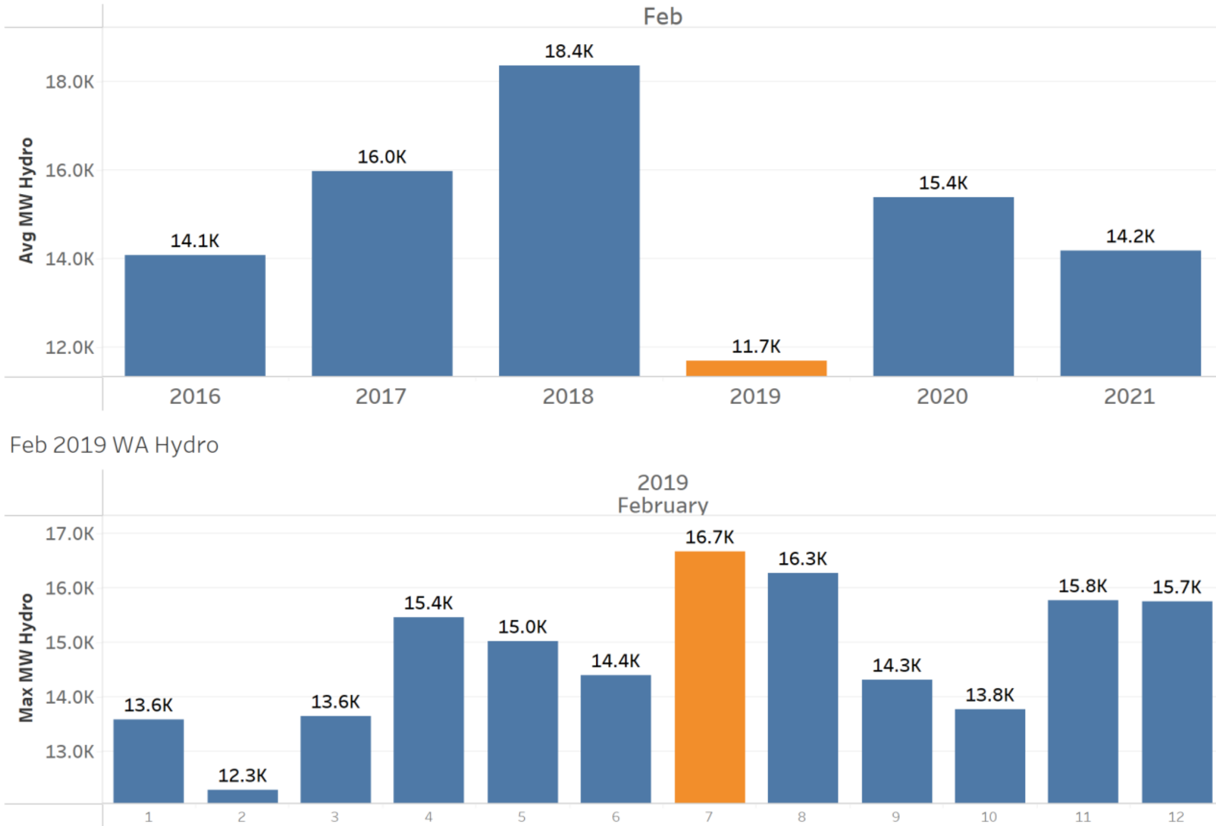
The top pane shows average hydro production for each February from 2016 to 2021. February 2019 was a very low month for hydro production, coming in at 11,700 MW which is well below any of the other years. It was this very low hydro production that directly contributed to the scarcity event.

The bottom pane shows maximum daily hydro production for Feburary 1 - 12, 2019. Although average production for the month was 11,700 MW (top pane), the system was able to ramp up to 16,700 MW of hydro output during the scarcity event.

It is noteworthy that this 16,700 MW is not only well above the monthly average, it is also 3,000 to 4,000 MW higher than output just a few days earlier. This ability, to temporary increase output to meet surging demand at such a large magnitude, is critically important to maintaining reliability in the PNW.

There was no other resource within the PNW region which was able to increase output to meet this surge in demand. Coal, nuclear, and Oregon natural gas generation held steady. Washington natural gas generation decllined. During these high atmospheric pressure weather events, the winds also become still. Only hydro was available to meet the moment.

Figure 67: Comparison of Average February Hydro Production to Max Production During Scarcity Event



8.3.4 Imports: Net Imports Also Increase to Meet Demand

The remainder of the increase in demand – approximately 6,000 MW – was met with imports. The next figure clearly exhibits this impact.

In Figure 67 on the following page, the top pane shows how unique the transmission flows were for the month of February 2019. In all other years, the PNW was a net energy exporter for the month of February. In 2019, the flows reversed and imports averaged about 3,000 MW. Note that this is a change of +8,000 MW from 2018 and 2020. The imports in February were unprecedented.

The bottom pane shows the maximum daily imports throughout the month, with February 7, 2019 highlighted as the scarcity day. Both the average monthly and the maximum daily imports set all-time records for the PNW in February and March of 2019.

These imports reflects flows from the north with British Columbia, the east with Idaho and Montana, and the south with California.

Figure 68 shows the very carefully orchestrated dance between the regions that provided the PNW with sufficient energy to avoid blackouts via hourly imports for each tie line.

Figure 68: PNW Net Transmission (MW) – Average by Month and Max by Day

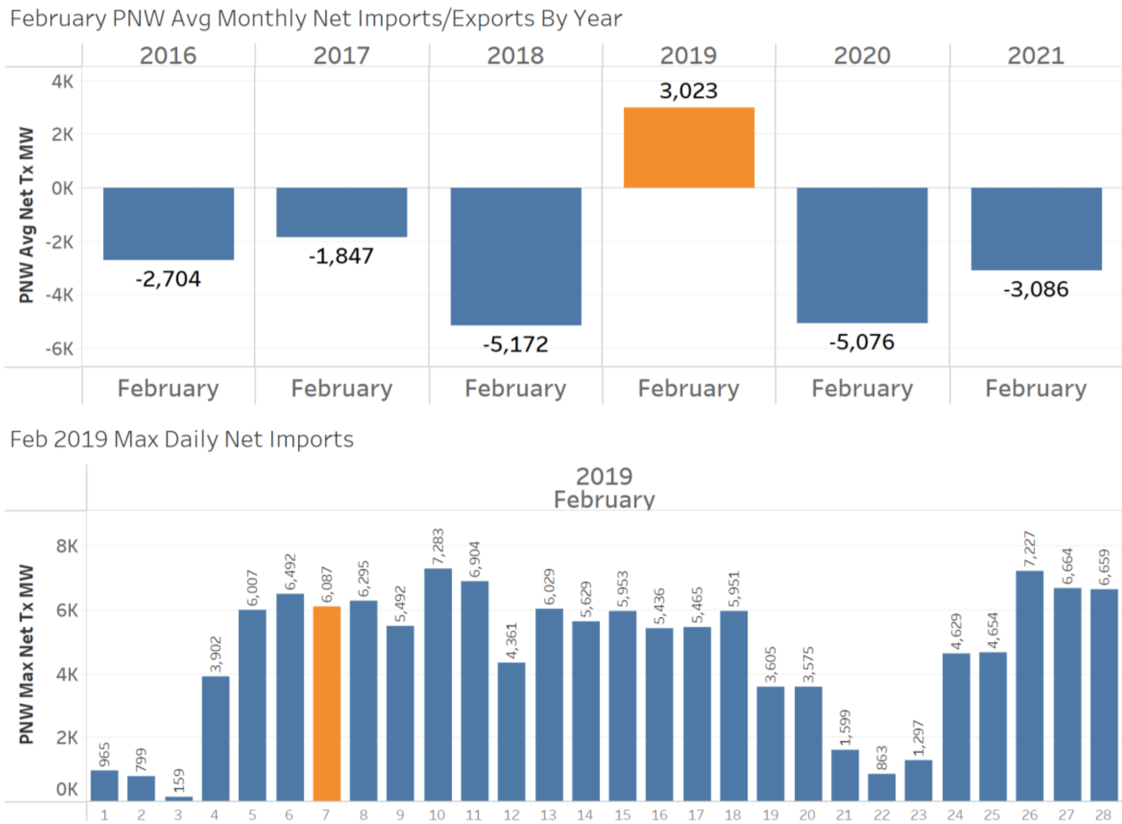
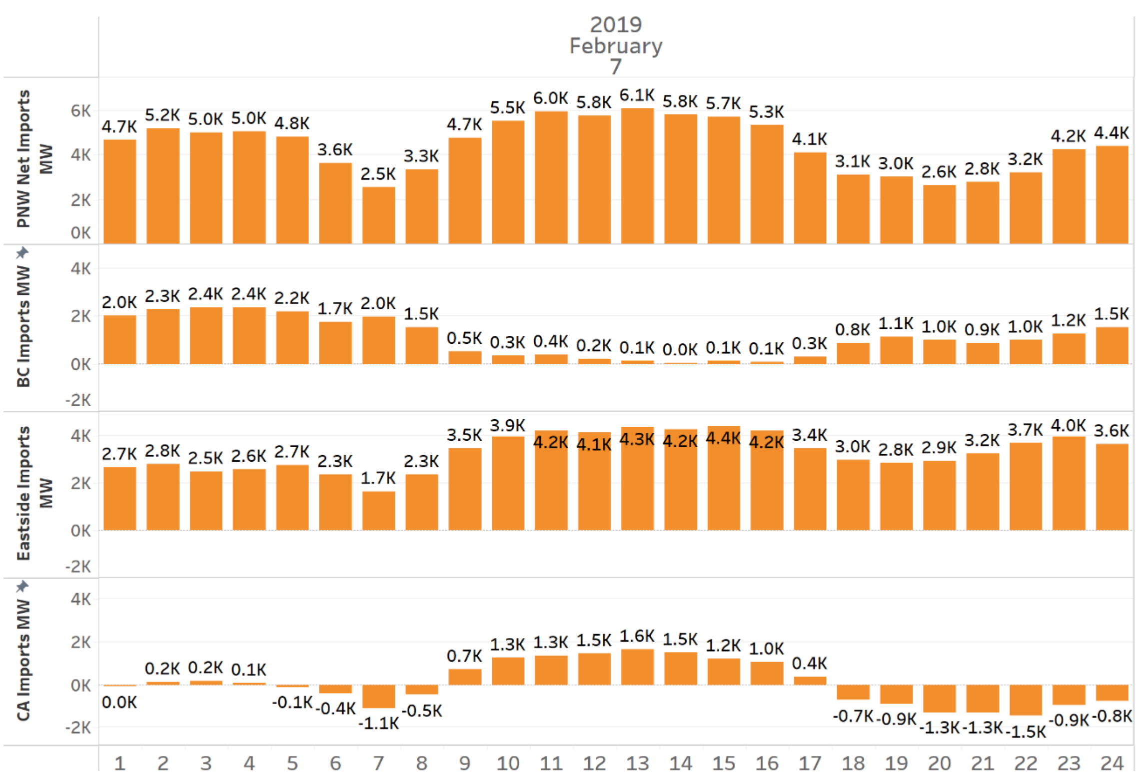


Figure 69: Hourly Imports by Region for February 7, 2019 (MW)



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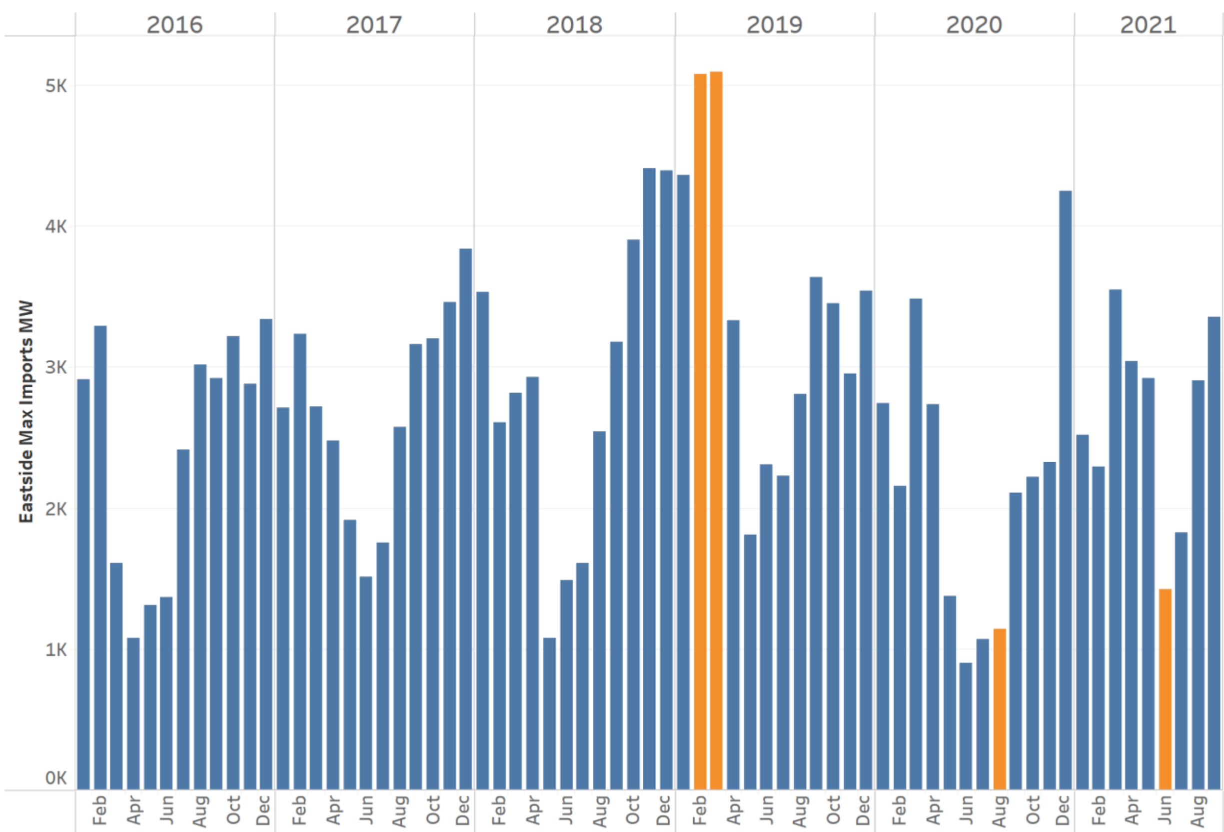
Takeaways from Figure 68:

- Net imports reached a maximum of 6,100 MW in the middle of the day on the 7th.
- The BC system was able to send more than 2,000 MW of supply to the PNW during the overnight hours.
- The East side sent up to 4,400 MW to the PNW during the middle of the day, ramping up its deliveries during the hours when BC imports declined.
- California took energy from the PNW during the overnight hours (negative numbers) but was able to send up to 1,600 MW to the PNW during the solar hours.

It is important to point out that few of these imports had any obligations to deliver to the PNW – the PNW had no right to this capacity. This energy made its way to the PNW as a result of market sales which followed the high prices at the Mid-C. This is an example of the benefits of resource diversity, markets, and the power of price signals. However, there is no guarantee that this supply will be there during future scarcity events.

The key import region during this event was the East side: Montana and Idaho. The figure below reminds us just how extra-ordinary the East side imports were during the February 2019 scarcity event and the period during February and March 2019 with low hydro prduction and limitations on natural gas generation.

Figure 70: Maximum Imports from East Side by Month, 2016 to 2021



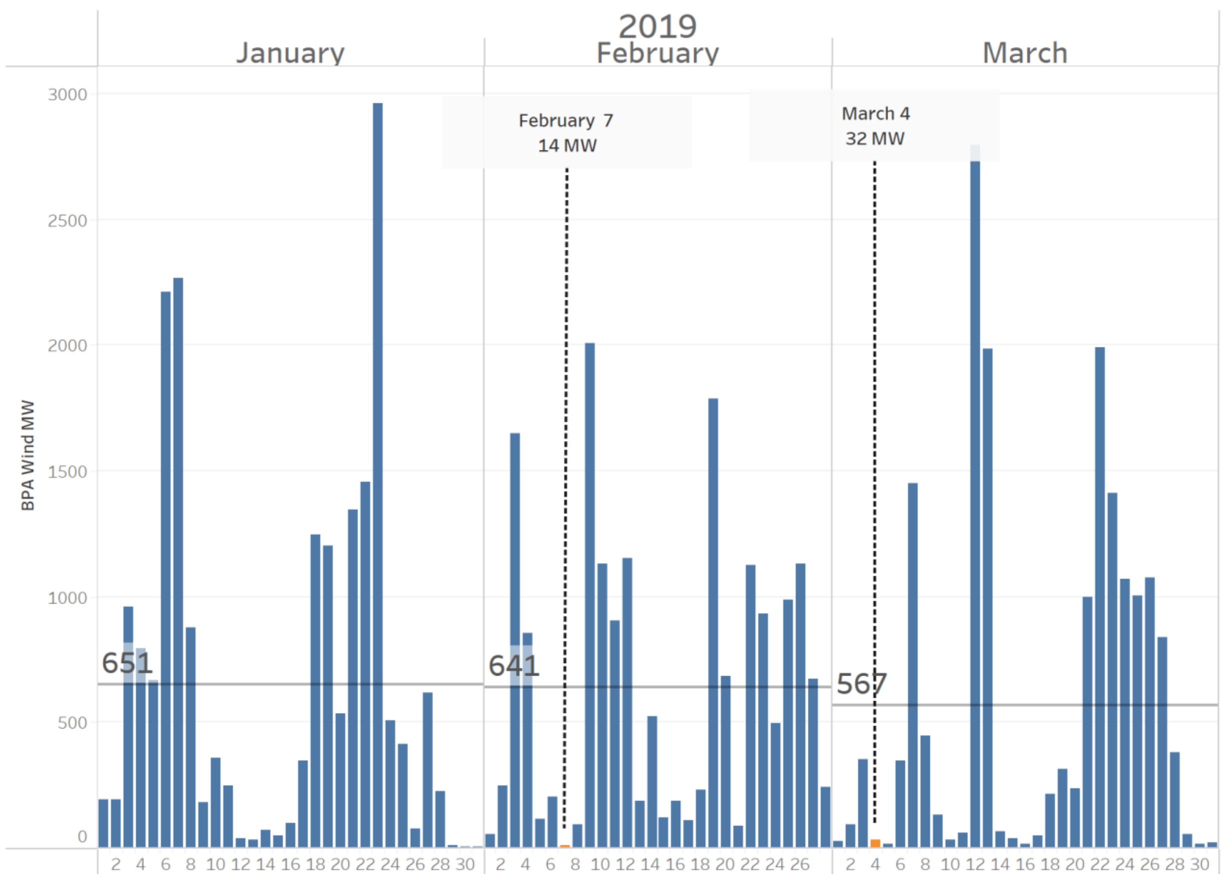
Maximum imports during February and March of 2019 hit 5,100 MW. The next highest import value in the entire six-year record is 4,300 MW in December of 2020 with no other time in the entire period breaching 4,000 MW.

It is notable that a significant portion of the imports from the East side came from the Colstrip coal plant, which retired two units in 2019 and has additional units slated to retire in the coming years. It would be unwise to bank on 5,100 MW of imports coming from the East side during a time of need in the future.

8.3.5 Renewables: Wind Was Low During the Scarcity Event

The figure below depicts average wind production by day for January - March 2019. During the scarcity events of February 7 and March 9 – as well as the days immediately surrounding these events – the wind barely blew and wind generation was extremely low.

Figure 71: Average Daily BPA Wind Production (MW), January - March 2019



The reason we show average (rather than max) for wind in this figure is because wind is not a dispatchable resource. Wind provides energy to the system when the wind blows, and the hydro system then responds to this variability ("balances") by producing more generation when wind is low and less when it is high. Given the extremely low wind production during the scarcity event in February (and March) there isn't a meaningful difference beween the average and the max.

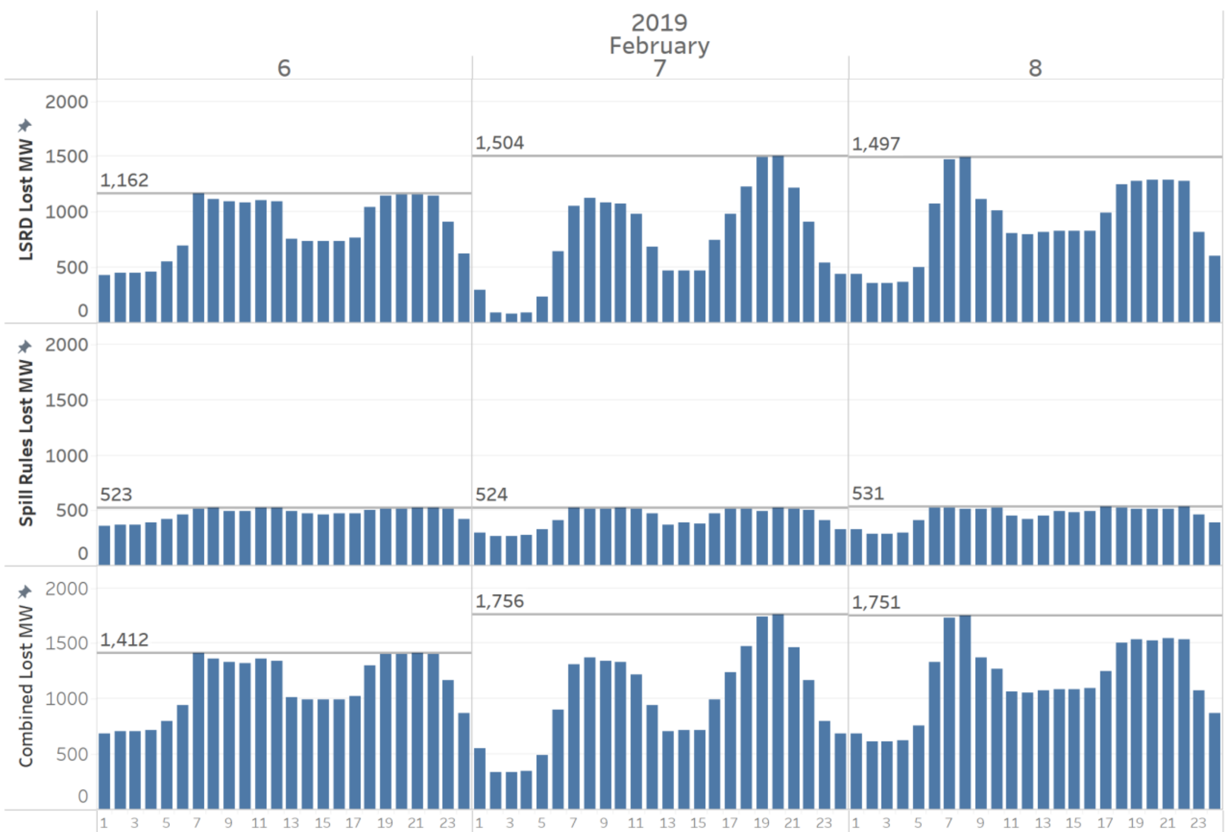
On February 7, average wind production from the entire BPA system was 14 MW compared to installed BPA nameplate capacity of approximately 3,000 MW. From February 5 - 8, BPA wind averaged less than 1,000 MW.

At the time when the need for supply was most acute, the wind was not blowing. The challenge of using wind to meet high loads is clear from the top pane, which shows the relationship between wind and load across 59 days in January and February 2019. During a large proportion of the days with the highest load, wind production was at low levels.

8.3.6 LSRD Analysis: Increased Spill and/or Removing the LSRD Removes Hydro Supply from times of Scarcity

Increasing spill requirements and/or removing the LSRD would further exacerbate supply challenges during scarcity events. The figure below shows actual hourly hydro production from February 6 - 9, 2019 that would be removed from the system either due to spill rules or by removing the LSRD.

Figure 72: Lost Hydro Generation from New Spill Rules and Removal of LSRD (February 2019)



The top pane shows the impact of LSRD removal. On February 7 and 8 this would have resulted in a loss of 1,000 to 1,500 MW during the critical hours. The second pane shows the impact of increased spill obligations on both LSRD and Lower Columbia dams. Spills would have resulted in a loss of about 500 MW during critical hours.

The bottom pane shows the combined impact (the two values aren't simply added together because some LSRD spill is in the middle pane as well). Increased spill and removal of the LSRD would have resulted in the need to replace more than 1,700 MW of supply during the February 2019 scarcity event.

8.3.7 Case Study 1 Conclusion

In summary, high demand during the critical days in February 2019 happened during a month with relatively low hydro production. Natural gas plants in Washington were not able to produce at maximum output because reduced flows on the Sumas pipeline limited the supply of natural gas, and that limited supply was required to meet heating demand. Other thermal resources in Oregon and Washington enjoyed strong performance, but these resources are limited in total capacity. (Further, with the coal retirements that have happened already coupled with the retirment of Centralia in a few years, this thermal stack in the PNW will be that much thinner.) Wind provided virtually no supply on these critical days.

But for the flexibility of the hydro system and unprecendented imports from other regions, it is not clear how the PNW would have balanced supply and demand. Removal of the LSRD and increased spill obligations would have removed about 1,700 MW of supply from the region. With all other sources of supply maxed out (and declining in the future), it is not clear how the system would have balanced without this 1,700 MW of hydro supply.

8.4 Case Study 2: March 2019

The challenges experienced by the PNW grid in Case Study 1: February 2019 happened again the next month. On March 4, Mid-C prices spiked above $800 per MWh. Relatively low hydro continued to plague the system. In addition, there was planned maintenance at Sumas which reduced the natural gas deliveries into Washington. March 4 was a Monday, which meant trading for that day occurred the previous Friday. The region scrambled to find supply which led prices to the highest levels observed at the Mid-C in about 20 years. By Monday, the pipeline maintenance was cancelled, allowing more natural gas to flow to Washington generators than was expected the previous Friday.

8.4.1 Baseload: Nuclear, Coal, and Oregon Natural Gas All Produced

The following Figure 72 shows maximum PNW demand, nuclear production, as well as Oregon and Washington coal generation for March 1 - 7, 2019.

PNW electricity demand on March 4 was down 2,200 MW compared to the scarcity event on February 7, however, 27,300 MW is still very strong winter demand. The nuclear and coal fleet again performed very well, with the Columbia Generating Station operating at 1,200 MW. Boardman and Centralia also operated within a couple hundred MW of maximum output.

Figure 73: Maximum PNW Demand, Nuclear and Coal Generation, March 1 - 7, 2019

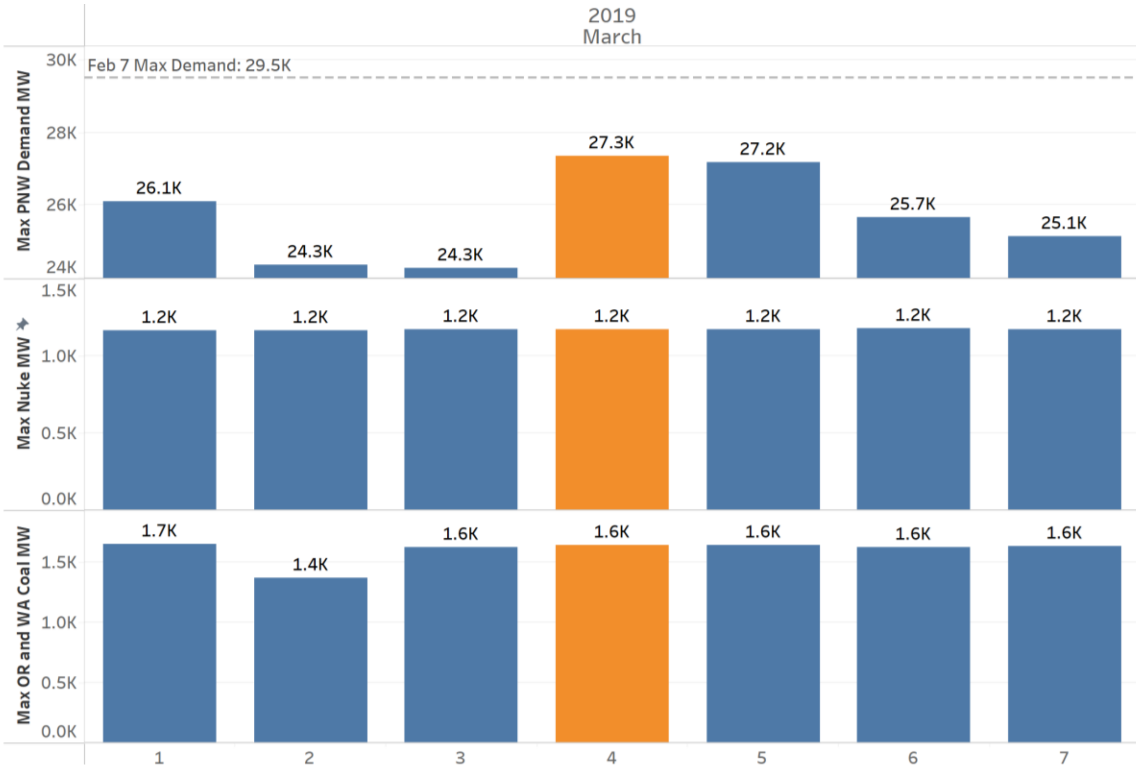
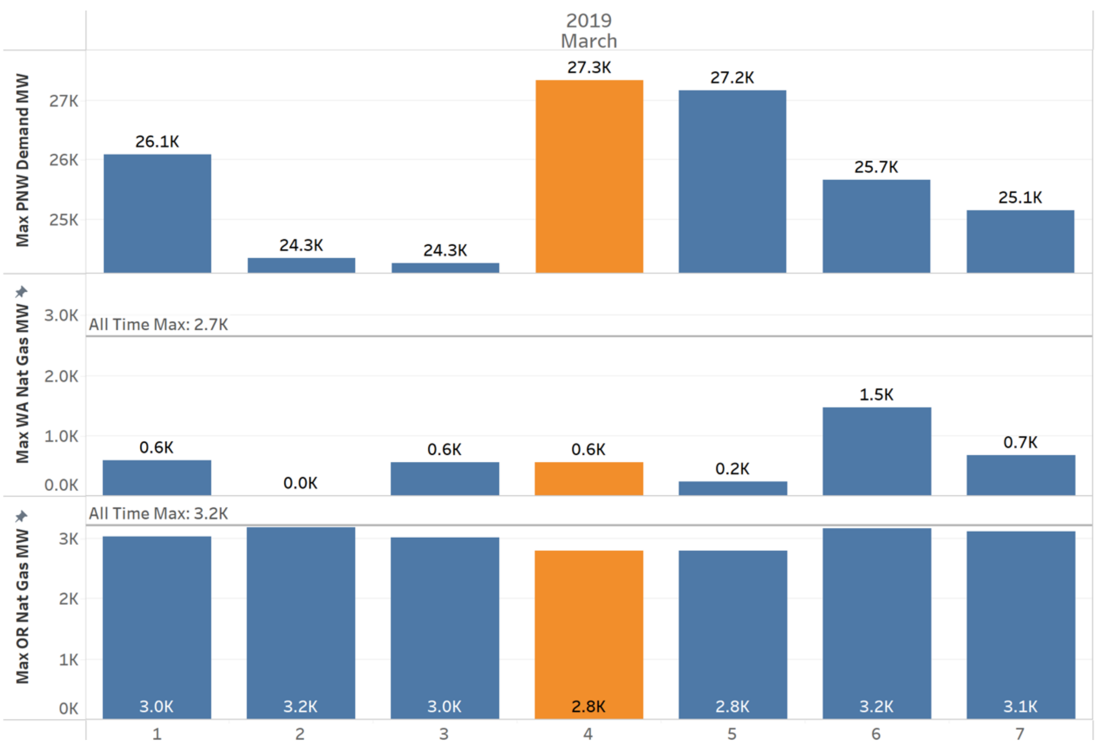


Figure 74: PNW Demand and Natural Gas Supply March 1 - 7, 2019 (MW)



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8.4.2 Thermal: Despite Record Power Prices, Natural Gas Prices Rise Even Higher for Heat

Natural gas demand in Washington is largely served via the Sumas pipeline and Jackson Prairie storage facility. After five months of constrained supply at Sumas, storage in Jackson Prairie was running low. When the cold snap hit Washington in early March, heating demand was in direct competition with electricity generation for the scarce natural gas.

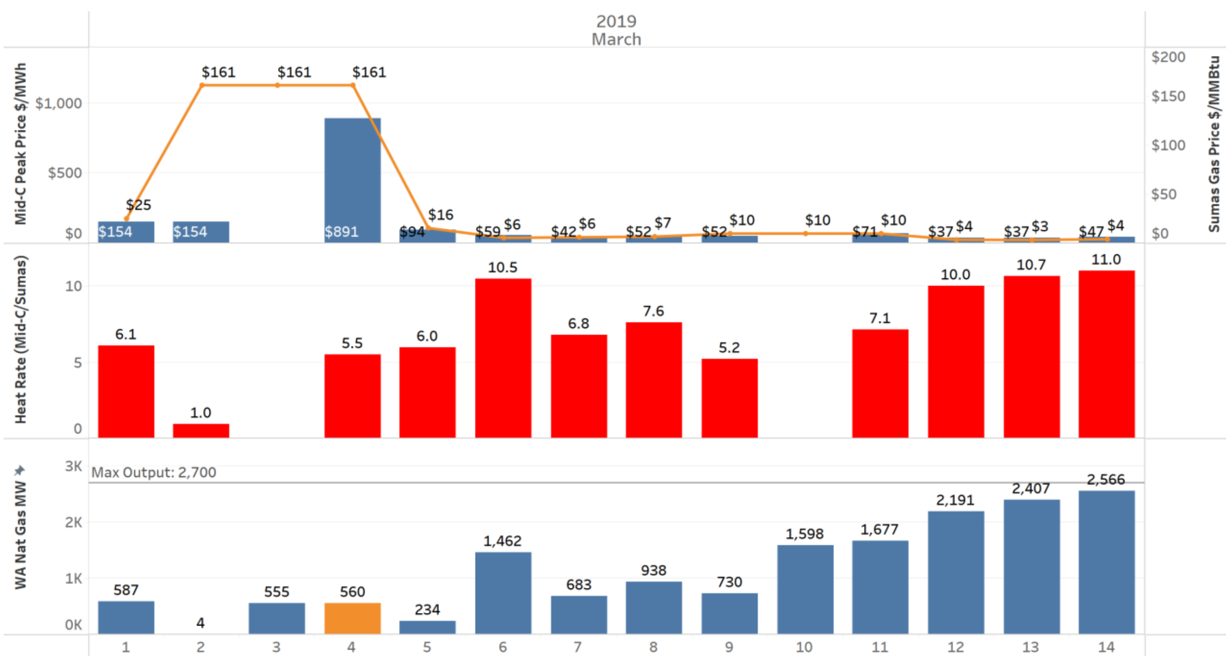
Figure 73 shows natural gas generation in Washington and Oregon for March 1-7, 2019.

Natural gas generation in Washington was even lower in March than it was in February. On March 4, when prices breached $800 per MWh, Washington natural gas generation was only 600 MW, a full 2,100 MW below the maximum that could be produced. Oregon natural gas supply was 2,800 MW, about 400 MW below maximum output. Combined, the PNW natural gas fleet produced 2,500 MW less than planners would have expected during a cold snap.

Just as we observed in the February scarcity event, markets use price to ration supply.

Figure 74 below shows Mid-C electricity prices, Sumas gas prices, and Washington natural gas production. Here we depict the first 14 days of March to illustrate the relationship between price and gas generation.

Figure 75: Electricity and Gas Prices, Market Heat Rates, and WA Gas Generation March 1-14, 2019



- In Figure 74, the top pane shows Sumas natural gas prices (orange line) and Mid-C power prices (blue bars). Like this same figure in the discussion of the February event, the Mid-C axis is 7x the Sumas axis. Prevailing natural gas prices in other regions at this time were in the range of $3.00 per MMBtu. Natural gas was so scarce in Washington that Sumas ran up to $161 per MMBtu. Mid-C prices climbed to $891 per MWh.

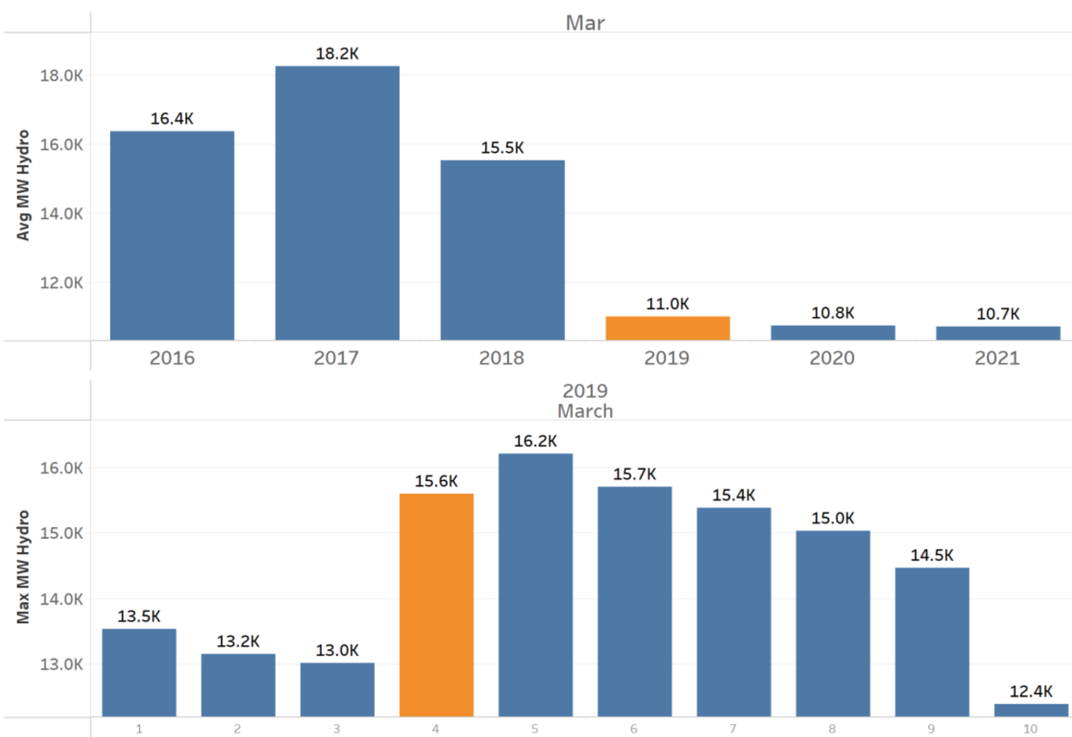
- The second pane shows the implied market heat rates (power price divided by gas price). As it turns out, $891 per MWh was not rich enough for efficient Washington gas generators to profitably operate – the implied heat rate on March 4 was 5.5 MMBtu per MWh.
- The response was predictable, as shown in the third pane: Washington gas generation was only 560 MW out of a total possible supply of 2,700 MW.

After the cold weather had passed, gas prices fell, and Washington natural gas generation was up to almost 2,600 MW by March 14. By this time, market clearing heat rates were up to 11.0 which meant that gas generators could operate with positive margins. Gas generators were available during this time, but there simply was not enough natural gas to deliver both heating demand and power generation, and as always, heating demand gets the scarce resource and the rationing signal is sent through market prices.

8.4.3 Hydro: Gas Plants Respond to Low Implied Heat Rates, Hydro and Imports Fill the Void

The rationing of natural gas, the limited imports (discussed further in next sub-section), and the response of the hydro system can be clearly seen in the Figure 75 below.

Figure 76: March Average Hydro and Max Daily Hydro March 1 - 10, 2019



The top pane in Figure 75 shows that the average March hydro generation was well below the prior three years. Low hydro generation creates an environment which is ripe for scarcity events.

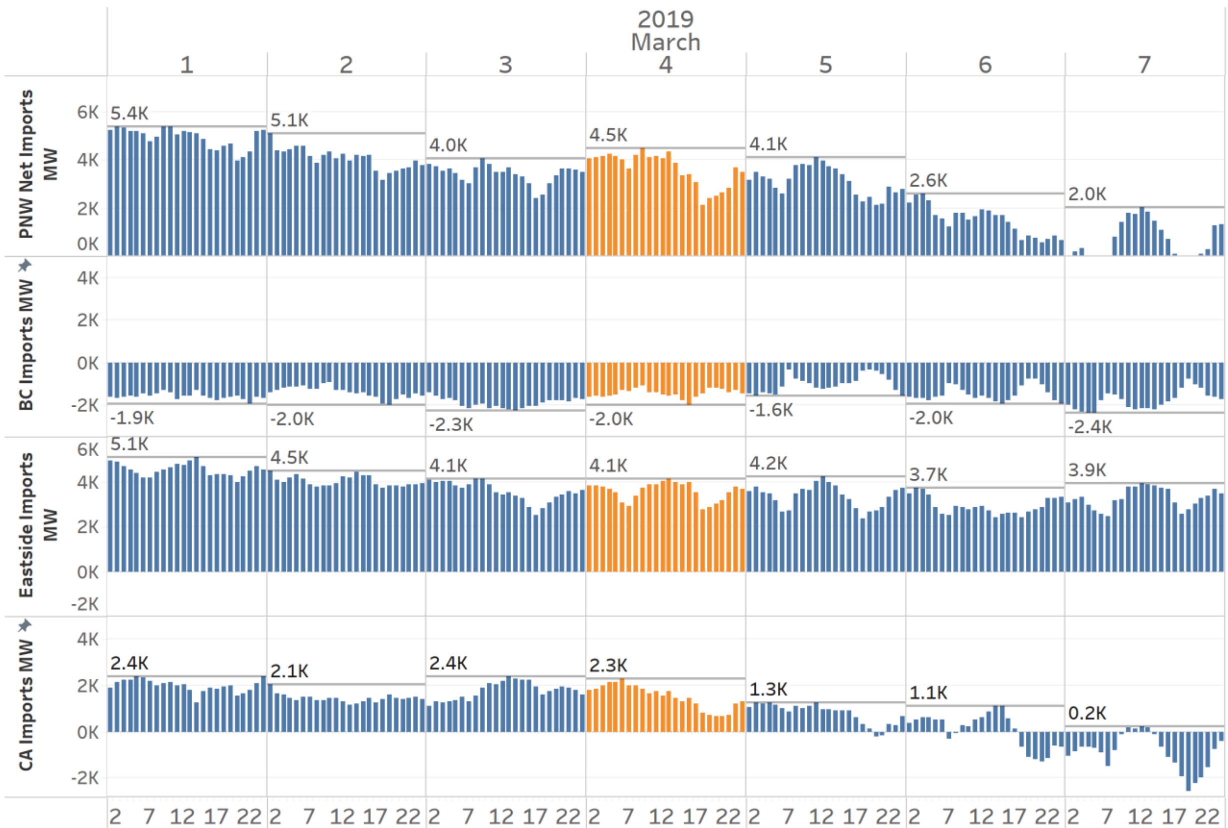
The bottom pane shows how the hydro system flexed between March 1 - 5 to meet the rising demand and to make up for some of the lost natural gas supply.

Indeed, the hydro system max output jumped by more than 3,000 MW from March 3 - 5. Recall from above that natural gas supply started to return during the second week of March. By Sunday March 10, maximum hydro production was below 13,000 MW. Again the hydro system provided the needed flexibility to meet increased demand, and at least partially, to offset a drop in natural gas generation.

8.4.4 Imports: Net Imports Also Increase to Meet Demand

In March as well as February, imported electricity helped balance the PNW market. The figure below shows hourly imports into the PNW from each of the surrounding regions.

Figure 77: Hourly Imports by Region for March 1 - 7, 2019



This import story is a variation on the same theme that we saw in the last case study. On March 4, the net imports totaled 4,500 MW which is 900 MW fewer than on March 1.

The second pane shows imports from British Columbia. Rather than sending electricity to the PNW, Washington was actually exporting to British Columbia: to the tune of about 2,000 MW during the highest hours. British Columbia had the same cold weather and natural gas challenges as the PNW.

Imports from the East side were quite strong on the 4th at 4,100 MW, but this is a full 1,000 MW less than the East side imports just three days earlier. Note that the as the price at Mid-C rose from \$154 per MWh on the 1st to \$891 MWh on the 4th, East side imports fell by 1,000 MW. They simply must not have had any more MW to give at any price on the 4th.

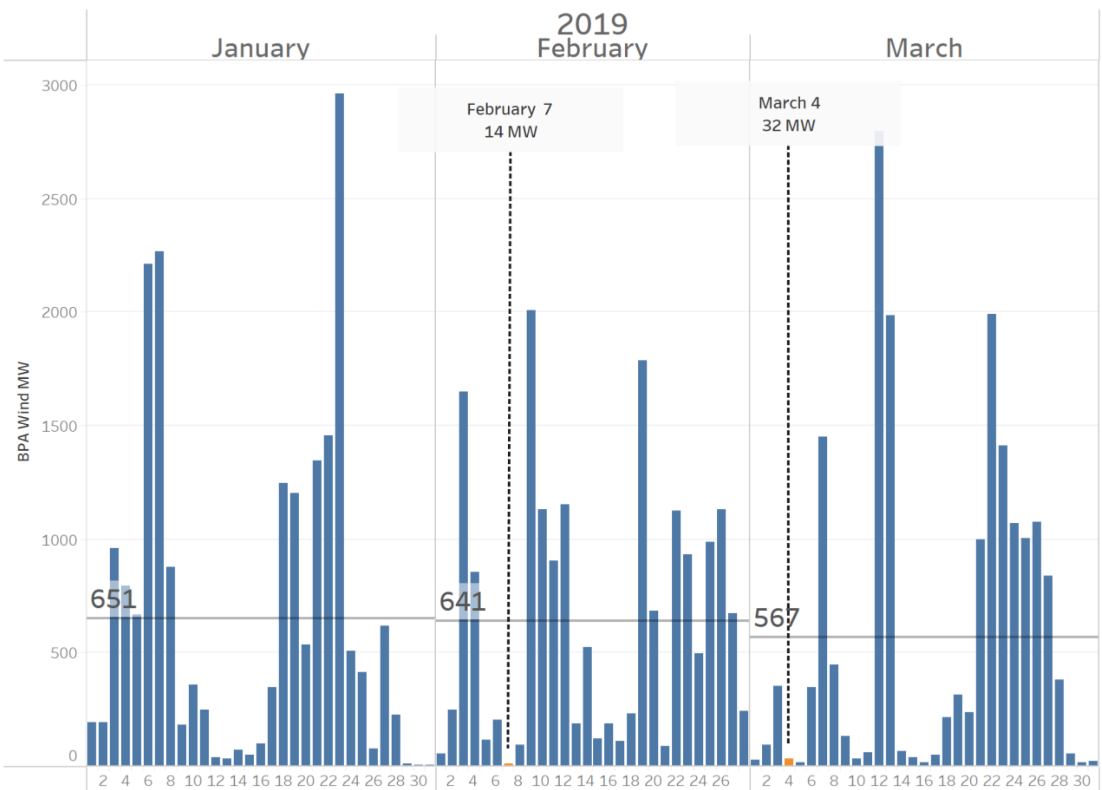
California was able to chip in another 2,300 MW to the PNW during the first four days of March. This is an impressive amount of imports from California by historical standards. However, when you consider the price of electricity in Southern California was about $70 per MWh on March 4 – a full $800 per MWh below the Mid-C price – it is noteworthy that all California could muster for export was a couple of thousand MWh.

Again, this pattern of imports shows the benefits of regional diversity, as the imports from British Columbia from February were replaced with California supply in March. However, very few of these MW were contractually obligated to come to the PNW, and under different circumstances, they may not have been available to the PNW region.

8.4.5 Wind Production During March Event Was Exceedingly Low

The wind story during the March scarcity event is almost identical to the story in February. The figure below is the same figure used in the discussion above about the February event.

Figure 78: Average Daily BPA Wind Production, January - March 2019

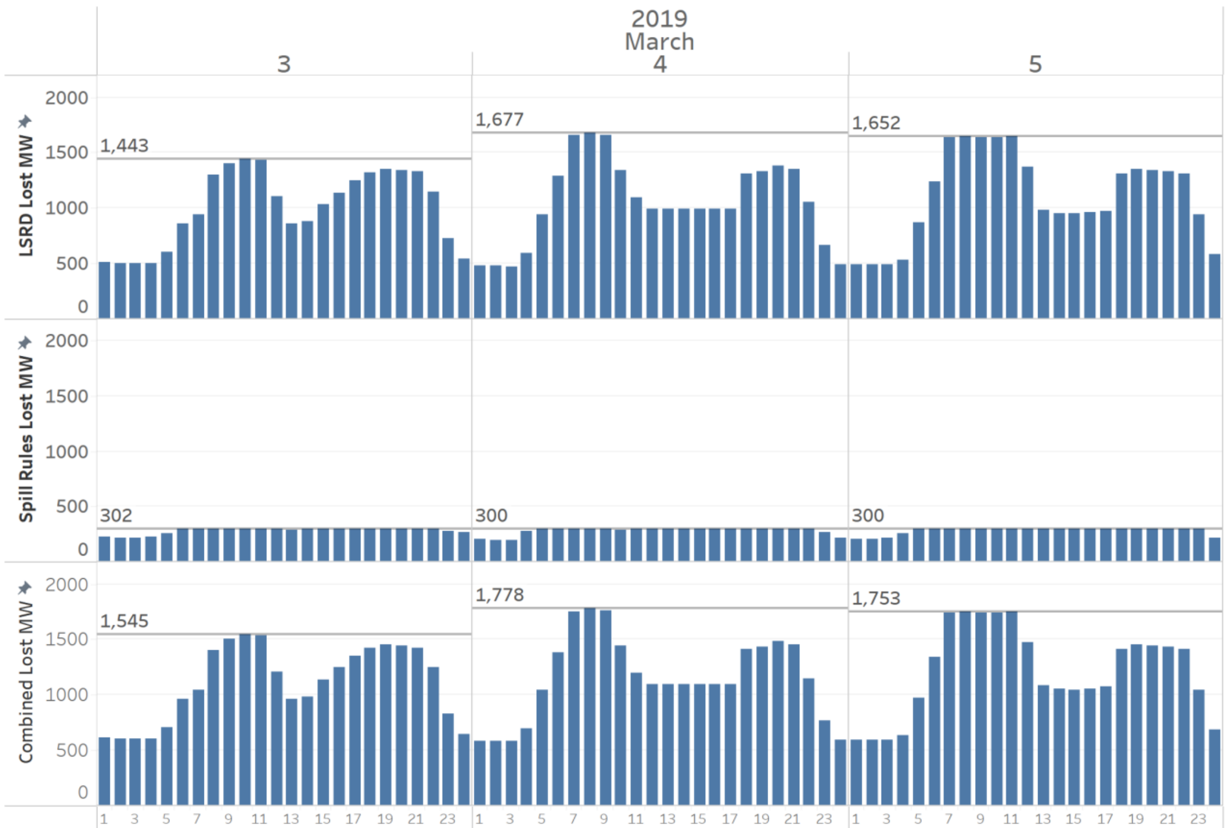


BPA wind production averaged 32 MW on March 4, 2019. This represents approximately 1% of nameplate BPA wind capacity. The days surround March 4 also show low levels of wind production. The average production for the months of February and March – when natural gas supplies were most constrained due to the outage at Sumas – totaled about 600 MW which represents a 20% capacity factor.

8.4.6 LSRD Analysis: Increased Spill and/or Removing the LSRD Removes Hydro Supply from times of Scarcity

The lost hydro generation associated with new spill rules or removal of the LSRDs is similar in March as we saw in February. The figure below depicts the lost hydro generation for March 3, 4, and 5 of 2019.

Figure 79: Lost Hydro Generation from Both Proposed Policies (March 2019)



There are several noteworthy themes in this graph:

The top pane shows production from the LSRD. Note these dams operated as peakers during the critical days of March 4 and 5.

Production during the morning ramp hours approached 1,700 MW on the critical days, up nearly 500 MW from the production profile on March 1. Production from LSRD exceeded that of most individual sources within the PNW Market: nuclear (1,200 MW), coal (1,600 MW), Washington gas (500 MW).

In addition, the LSRD production exceeded imports from BC and California. Only Oregon natural gas, imports from the east, and other hydro production played a larger role on the grid than the LSRD. The increased spill rules would have resulted in a loss of 300 MW, and the combined impacts about 1,800 MW.

8.4.7 Case Study 2 Conclusion

It is critical to understand the role of gas prices in this scarcity event. A power price in the hundreds of dollars per MWh was not able to cause more gas generation to come online or more imports to become available. The gas price for heating was high enough that it simply was not economical for most Washington natural gas units to run.

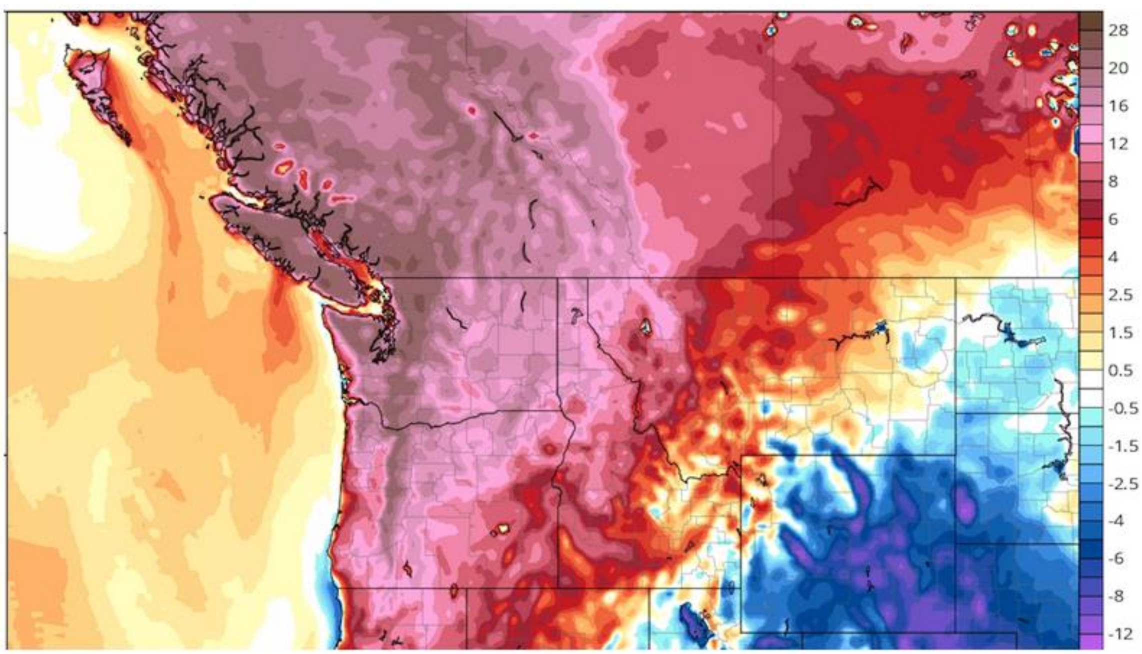
Meanwhile, other regions were dealing with balancing their own grids and didn't have enough power to send to the PNW. A price of $891 was not able to attract as many imports on the 4th as we observed on the 1st. It's not clear that additional imports would have been available at any price. This highlights than in some scarcity events, power may simply not be available for import to the PNW at any price and loss of additional hydro capability becomes even more critical.

Again, despite relatively low hydro supply, the system was able to flex its production and meet the increased demand. If another 1,700 MW of hydro was removed from the system due to spill and dam removal, it is not clear from where those MW would come.

8.5 Case Study 3: June 2021 PNW Heat Dome

The Pacific Northwest experienced record-breaking heat at the end of June 2021. Temperature records were set across the region between Sunday, June 27 and Tuesday, June 29.

Figure 80: Degrees from Normal for Monday June 28, 2021

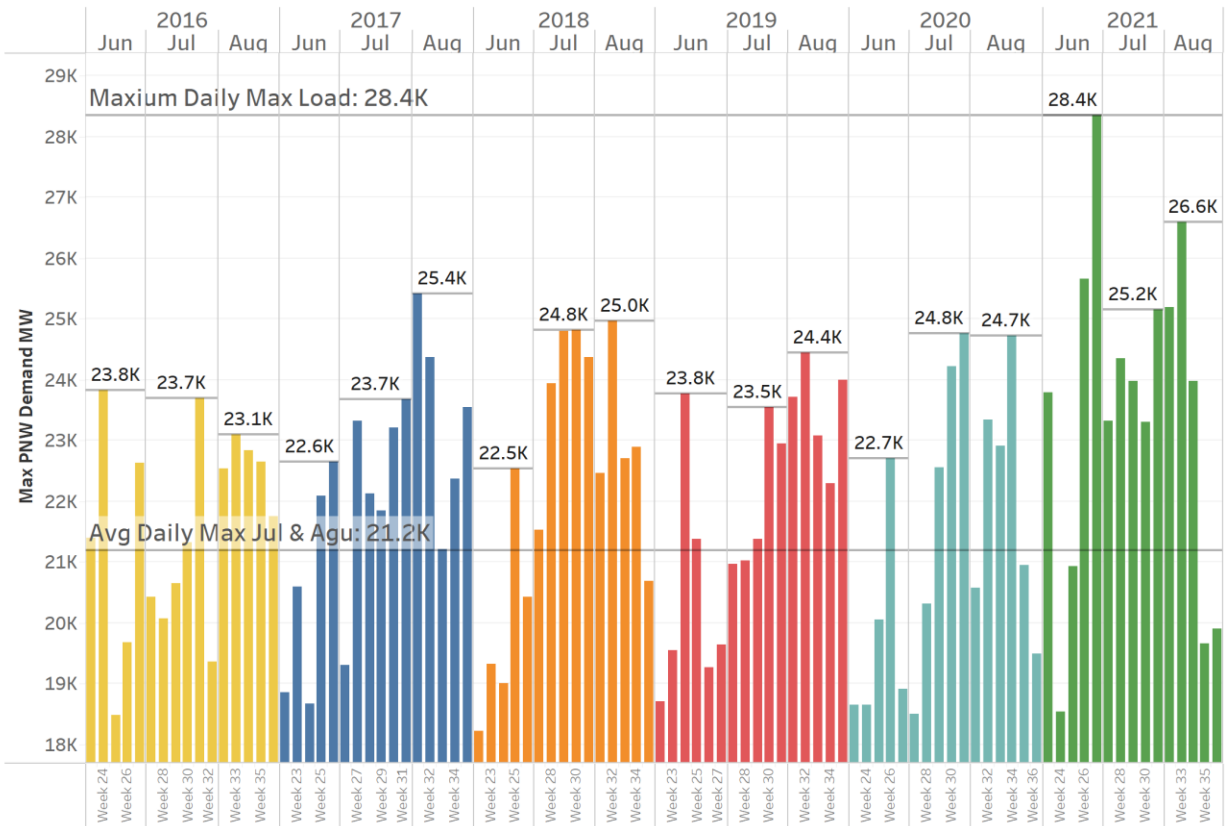


Computer model projection showing temperature departures from average on Monday, June 28, 2021. (tropicaltidbits.com)

The population centers along the I-5 corridor mostly set records on the 28th while locales east of the Cascades set records on the 29th. PNW electricity demand was highest on the 28th. The figure below depicts degrees from normal for the region.

As is the case with most reliability events, demand is an important driver. The figure below puts the heat dome demand into perspective. This depicts maximum hourly PNW demand for each week during the months of June through August for 2016 through 2021.

Figure 81: Maximum Hourly PNW Demand by Grouped by Week for July – August, 2016 to 2021



The color coding simply separates one year from the next. Each reference line depicts the maximum hourly demand for each month.

Maximum PNW peak demand on June 28th reached 28,400 MW. This was a full 3,000 MW greater than the prior summer demand record set on August 3rd, 2017, and more than 7,000 MW above the historical average maximum demand for July and August!

The summer of 2021 shattered all sorts of demand records. The previous record summer demand of 25,400 MW was exceeded on four days in June 2021. July of 2021 set a new maximum demand record for the month of July. August of 2021 broke the previous August record on three separate days, putting in a maximum hourly demand value that was a full 1,000 MW greater than the previous August record.

Signs of climate change abound. The heat dome was an extraordinary event. But the entire summer of 2021 reveals the fingerprints of climate change impacts on electricity demand. Temperatures are rising and the proportion of homes with air conditioning is increasing too.

8.5.1 Baseload: Coal Generation Lower Due to Retirements, Nuclear and Coal Generate Baseload Energy

We now turn our attention to the supply stack during the heat dome. The figure below shows maximum daily PNW demand, and nuclear and coal production for June 23 - 30, 2021.

Figure 82: PNW Maximum Daily Demand, Nuclear, and Coal (MW), June 23 - 30, 2021

By June 24, demand was already running above normal maximum summer demand. In the ensuing week, demand increased by 5,000 MW, reaching its maximum on June 28.

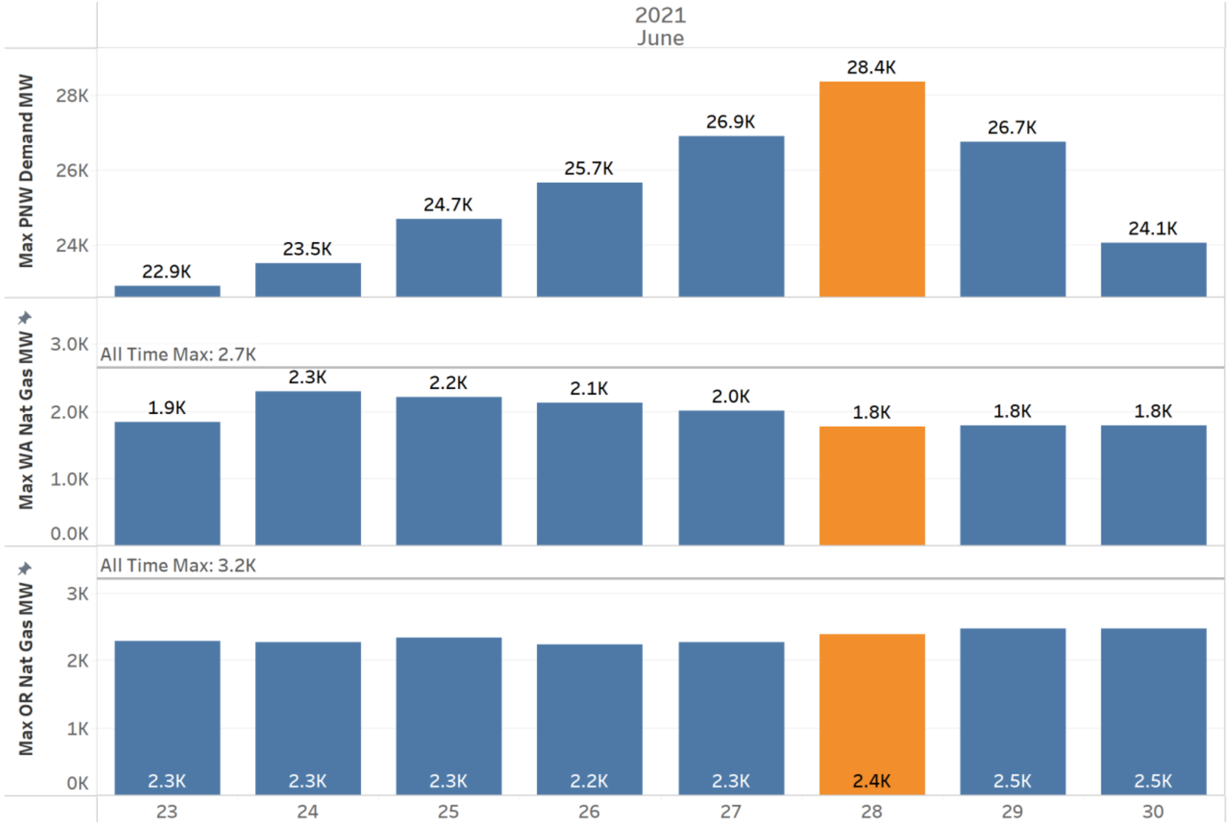
The nuclear generating station, which had been out for maintenance earlier in the month had returned to full service.

Coal generation in the region was limited to 670 MW from Centralia. In 2020, the Boardman coal plant in Oregon was retired and one of the two units at Centralia had been retired. Coal supply was down 900 MW from prior scarcity events.

8.5.2 Natural Gas: Oregon and Washington Natural Gas Below Full Capacity, Likely Due to Maintenance Outages

The next figure shows natural gas production during that week.

Figure 83: Maximum Natural Gas (MW), June 23 - 30, 2021



The first pane shows total demand (the same info as the first pane in the previous figure). The second pane shows Washington gas generation, and the third pane shows Oregon.

Note that running a natural gas plant during this period would have been highly profitable. Natural gas prices were low and stable, between $3.50 and $4.00 per MMBtu, with a cost of generating electricity in the $35 to $40 per MWh range. The price of electricity increased from $37 per MWh on June 24, up to $334 on June 30.

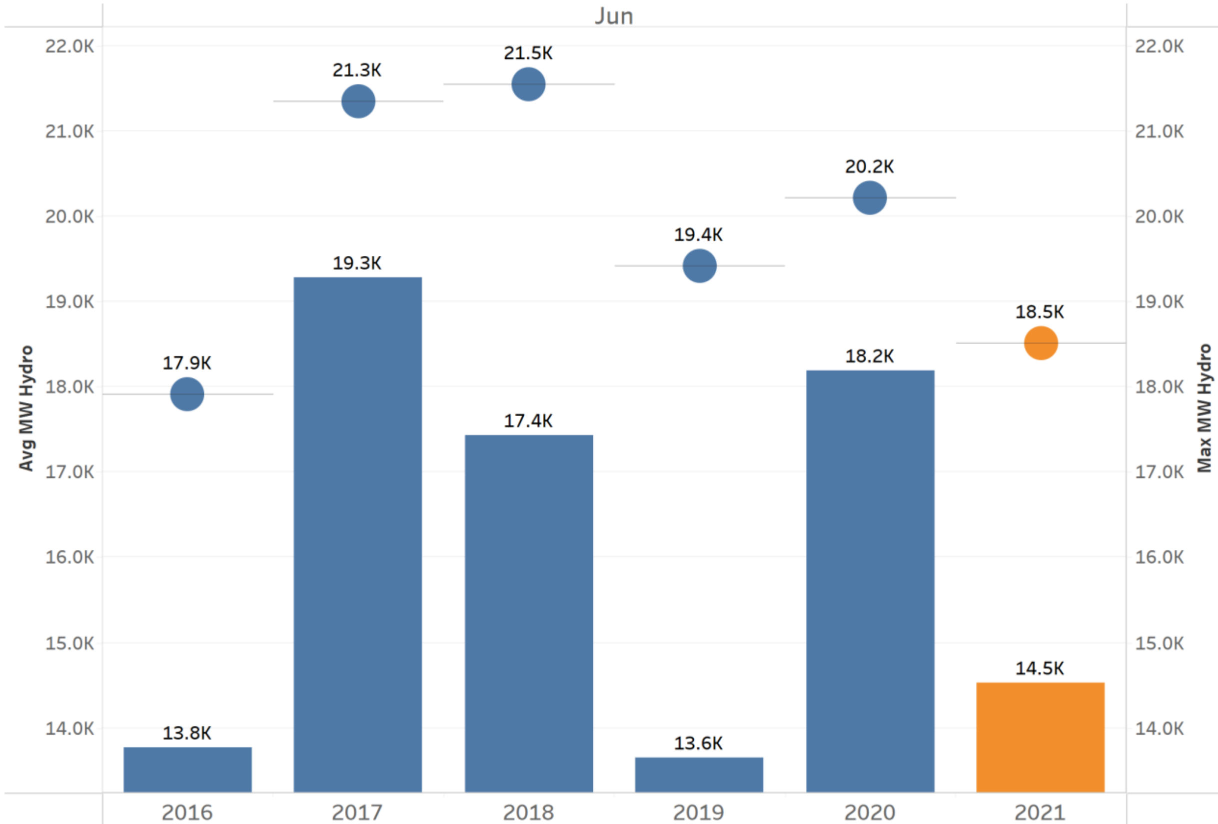
Given the demand and the price signal, all available natural gas generation would have been running. This equated to 1,800 MW from Washington and 2,400 MW from Oregon. Washington natural gas generation was about 1,000 MW below its installed capacity, while Oregon's was about 800 MW below it installed capacity.

There is no publicly available data to inform why these generators were not operating, but it was likely due to outages, whether forced or planned. Stated simply, on the day with the highest summer demand in PNW history, approximately 1,800 MW of natural gas generation was not available to meet load.

8.5.3 Hydro: Production Responds to Increased Demand

June 2021 was a strange runoff picture on the PNW hydro system. In many years, hydro production exceeds 20,000 MW in early June, and total production is often in the 15,000 - 20,000 MW range for much of the month. Extremely dry conditions and early runoff that spring resulted in low overall June flows. The figure below shows hourly hydro production for the entire months of June from 2016 - 2021.

Figure 84: Average and Max Monthly Hydro (MW) for the Month of June, 2016 - 2021



June can be quite a variable month depending on the volume of runoff as well as the timing. In some years, the peak runoff occurs at the end of May, while in others, when the snowpack is larger or the spring weather is cooler, the runoff is more concentrated in June. Hydro production in June of 2021 was below average but in no way out of the ordinary with average production of 14,500 MW and maximum hourly output during the month of 18,500.

The snowmelt runoff in June created a “double hump” production profile where there was a production peak early in the month and then a second, smaller production peak later in the month. Given the size of the Columbia River basin, it is reasonably common to have a roller coaster shape to the runoff, when different portions of the basin hit peak runoff at different times.

Figure 84 shows daily maximum hydro production for the months of May through July.

Figure 85: Daily Maximum Hydro Production (MW), May - July 2021

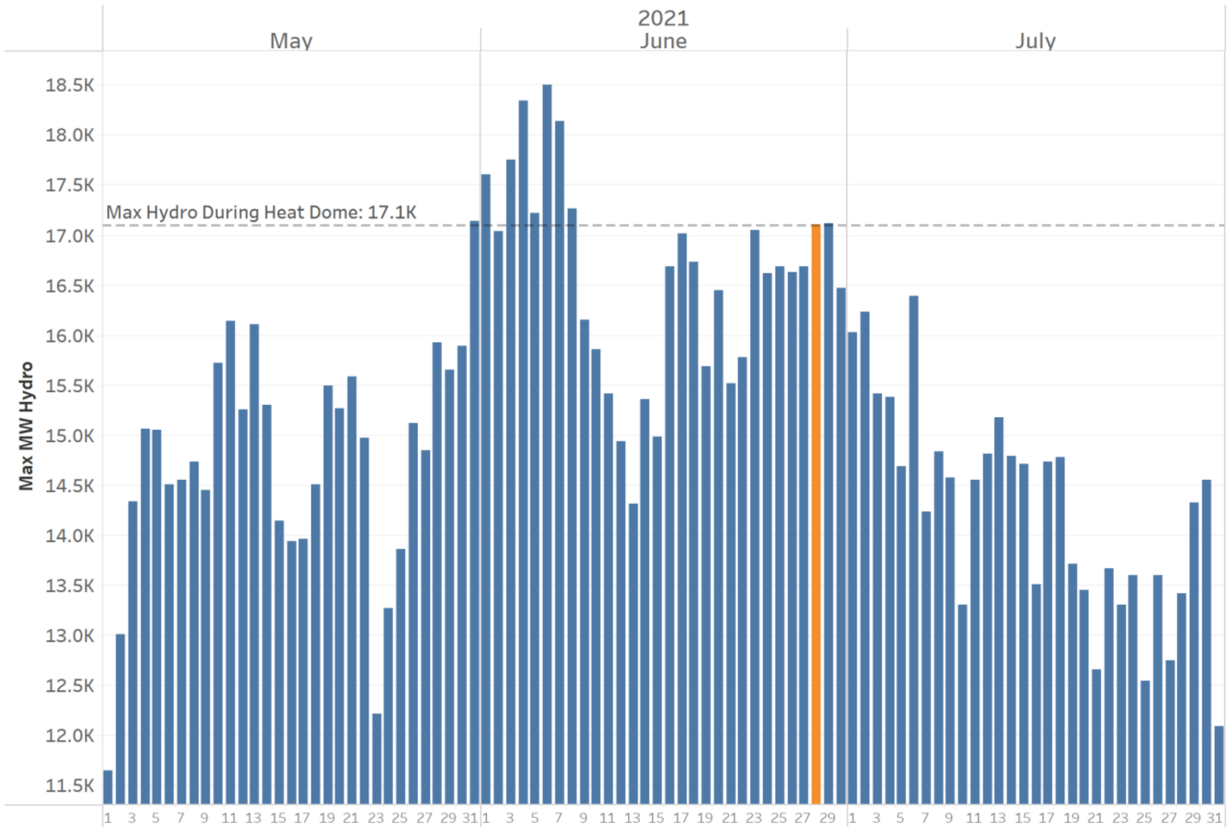
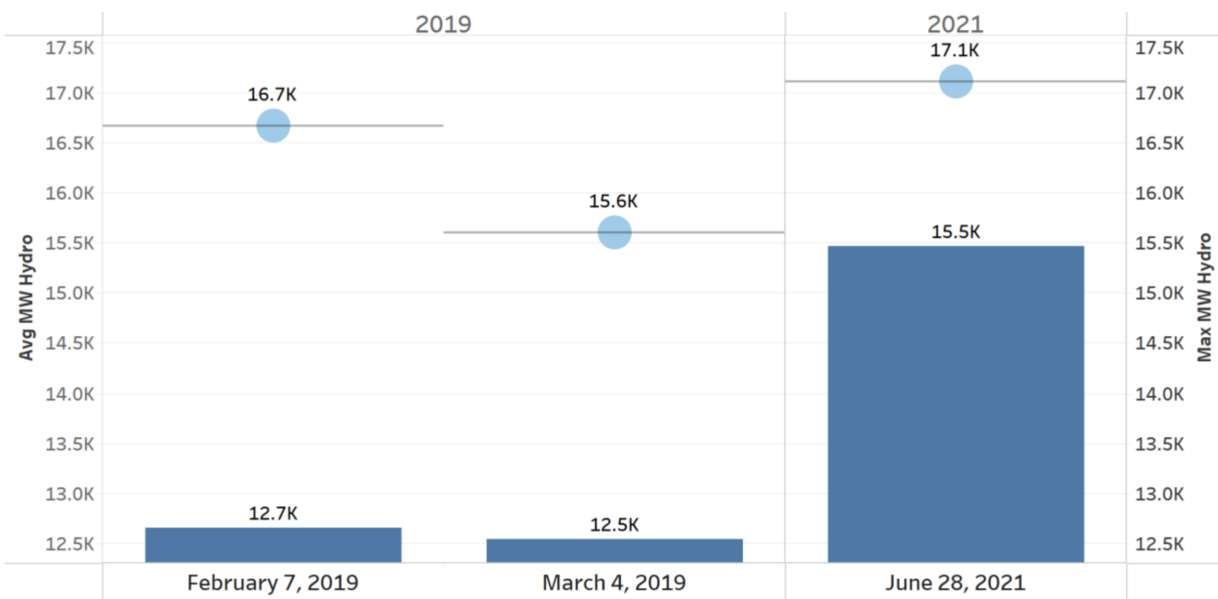


Figure 86: Average and Maximum Hydro MW During Scarcity Events



The heat dome hit right at the end of June at the tail end of the second production peak in June. Had the heat dome hit several weeks later, the hydro supply situation would have looked very different. As it played out, the system was able to generate 17,100 MW over the two-day period when the heat dome was most intense.

This 17,100 MW of maximum supply was 500 MW higher than maximum hydro production during the February 2019 scarcity event and 1,500 MW higher than the March 2019 event.

It can also be helpful to look at average hydro production, since the total amount of energy available to the system is also informative.

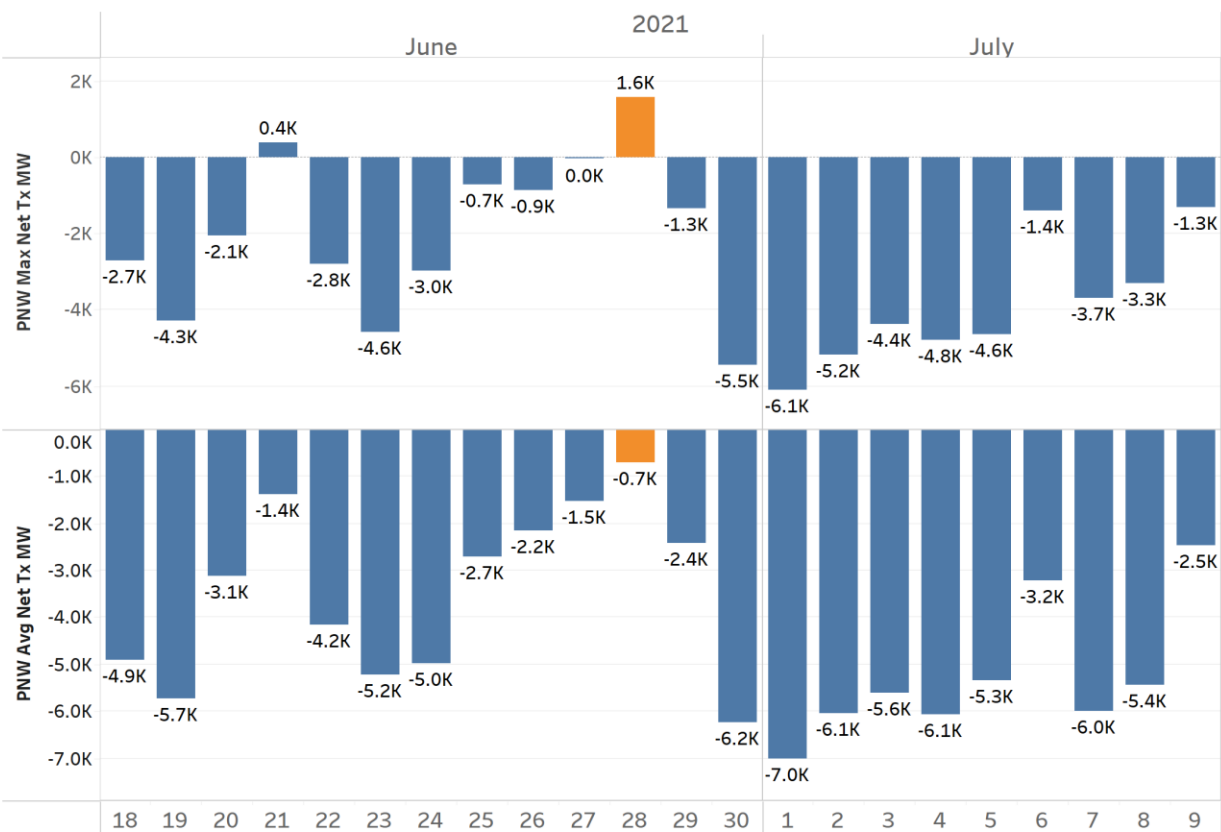
Figure 85 compares average daily hydro to maximum hourly output during the three scarcity events: February 7, 2019; March 4, 2019; and June 28, 2021.

During the June 2021 heat dome event, average hydro production was 15,600 MW – which is 3,000 MW more than the average production of the February and March of 2019 events. As we will see further below, this greater supply provided a great buffer for the PNW system and enabled the region to export MW during this period.

8.5.4 Imports: PNW Region is a Net Exporter During this Period

Let's turn our attention to imports now. The figure below shows net imports into the PNW for the 10 days on either side of the heat dome event at the end of June.

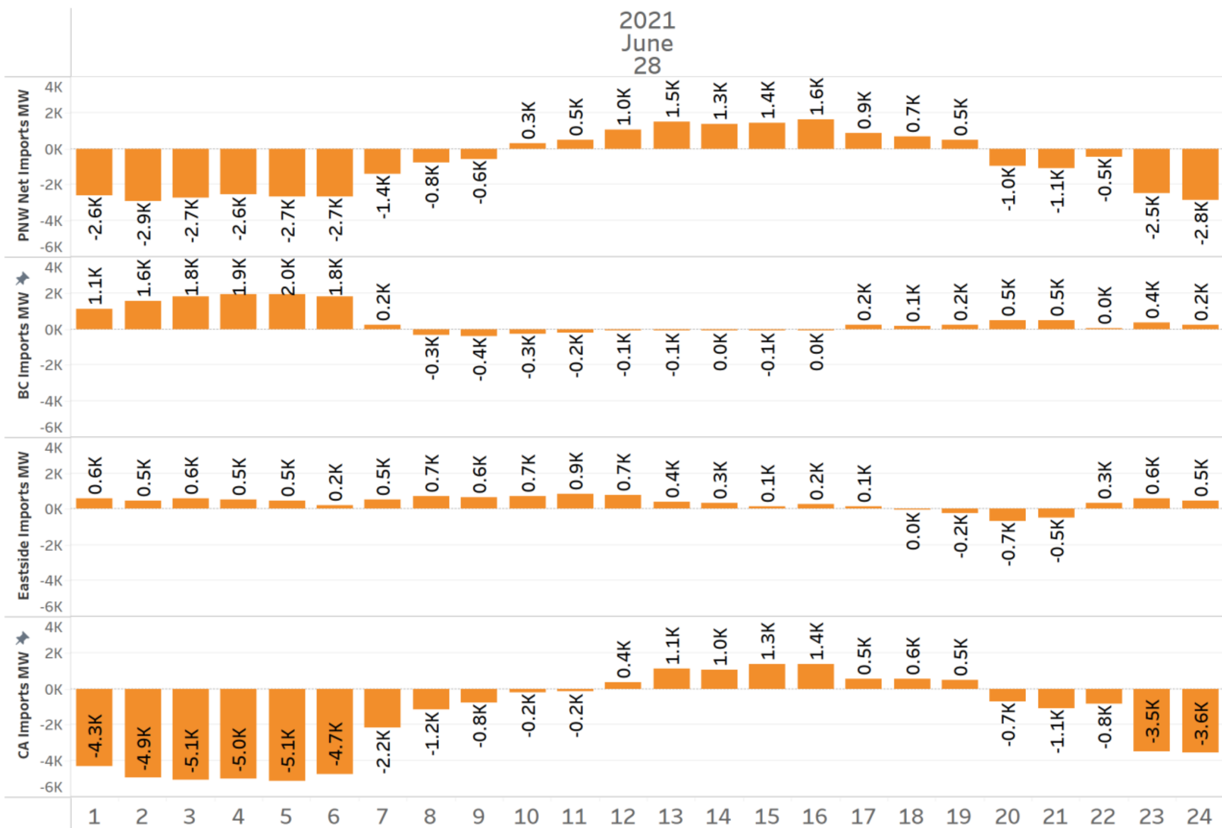
Figure 87: PNW Max Net Imports and Average Net Imports, June - July 2021



During the month of June, it is typical for the PNW to be exporting energy, especially excess hydro production to California. The pattern of exporting 2,000 - 5,000 MW on an average day is quite typical. When PNW demand was highest on the 28th, the region still exported an average of 700 MW to surrounding regions, although during the maximum hour the PNW imported 1,600 MW. The import/export picture for this scarcity event looks much different than the winter events.

The following figure shows hourly imports from the surrounding regions.

Figure 88: Hourly Imports/Exports into the PNW for June 28, 2021



The import/export pattern is sensible:

- During the night when loads dipped down some, the PNW region had sufficient supply to export to California.
- There was very little activity on the ties to the East side.
- Most of the imports into the PNW during the daytime came from California. On June 28, the price at the Mid-C was $334 per MWh while the price in California was only $102 per MWh. Despite an arbitrage opportunity of more than $300 per MWh, the maximum exports from California were only 1,400 MW.

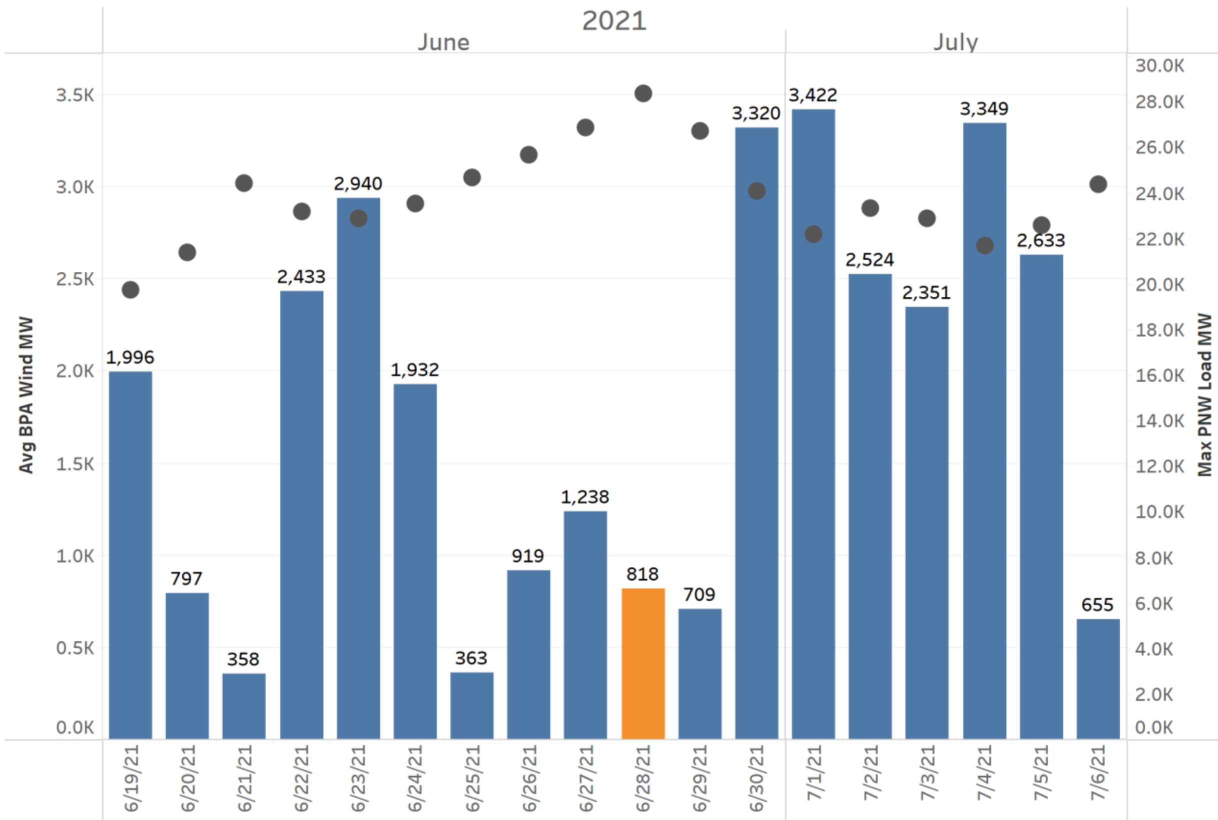
This import situation is concerning as the surrounding regions had very little to provide to the PNW during the heat dome. While it is understandable that BC, which was even hotter than the domestic PNW, had very few extra MWh to sell, the very limited imports from California cannot be explained by constrained supply or high demand as the heat dome did not directly hit California.

8.5.5 Wind Production During June Event Was Quite Low

The wind story during the heat dome 2021 scarcity event is almost identical to the story in the winter of 2019.

The figure below shows average daily wind production and maximum load for the days surrounding the scarcity event at the end of June 2021.

Figure 89: Average Daily BPA Wind Production (MW) Compared to Max Daily PNW Load (MW), June 19 - July 6, 2021



The pattern is familiar – as demand started ticking higher on June 24, wind began to drop off. On June 28, wind averaged 818 MW.

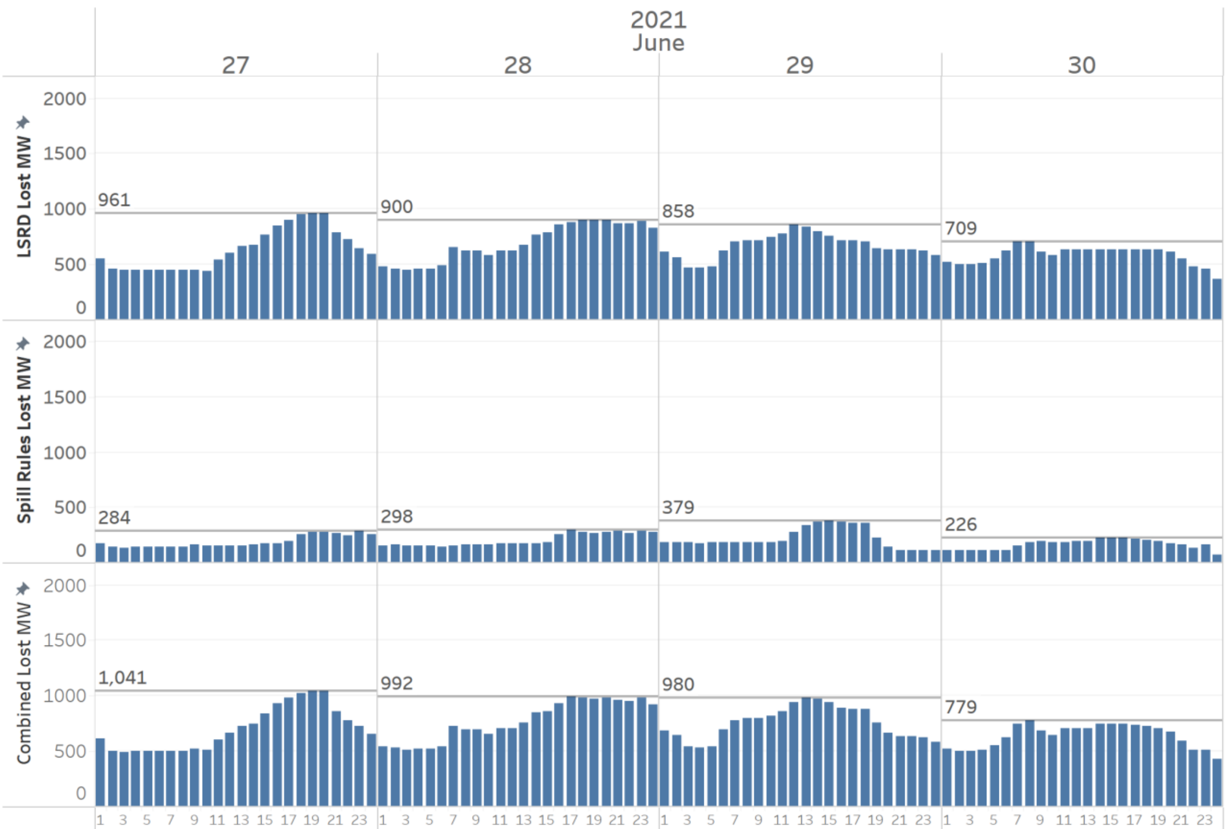
This is considerably better performance than in February and March of 2018, but the unfortunate coincidence occurred again: during a time of increasing load there was a time of decreasing wind. The wind on the 28th was quite variable, with the highest hourly wind value of 1,623 MW and the lowest hourly value of 321 MW.

8.5.6 LSRD Analysis: Increased Spill and/or Removing the LSRD Removes Hydro Supply from times of Scarcity

The figure below shows the amount of hydro generation that would be lost due to spill rules or breaching the LSRD.

The figure depicts hourly values from June 27 - June 30 during the heat dome of 2021.

Figure 90: Lost Hydro Generation from New Spill Rules and Removal of LSRD (June 2021)



Production on the Snake River was particularly low during this period, which in turn, makes the lost production low as well. The rivers feeding into the Lower Snake – the Salmon, Clearway, and Selway rivers – were experiencing extremely low flows.

It appears that BPA was managing the Lower Snake as an energy resource on these days rather than shaping production during the afternoon hours. That is, the production was relatively even throughout the day rather than large spikes in output during the evening peak hours.

Nonetheless, production on the LSRD was about 900 MW during the critical evening hours and the resources had 500 MW of flexibility between the lowest production hours and those with highest production. The spill rule impacts during June have a smaller impact of a few hundred MW.

8.5.7 Case Study 3 Conclusion

The June 2021 heat dome event reveals a different combination of the supply and demand elements that can go right or go wrong.

On the demand side, the PNW is still a winter-peaking region (for now), so even with record-breaking heat, maximum demand came in about 1,000 MW lower than the winter peak.

Most importantly, average hydro production was 3,000 MW greater during the heat dome than in February or March of 2019. This is good fortune that reservoirs are nearly full at the end of June and the overall level of flows on the Columbia River system are still high. As we saw in the daily hydro figure above, had the heat event hit several weeks later the hydro supply would have been considerably less.

Wind performed much better during the June event, averaging just over 800 MW rather than less than 100 MW during the winter events.

Imports and exports were reasonably balanced during the event, with the PNW net exporting a small amount during this period. The lack of imports from California even though prices in the PNW were more than $300 MW higher than in California is concerning. The Northwest received few imports from BC or from the East side as those regions were also struggling with the heat. The CAISO did not experience extreme weather at this time and still provided only 1,600 MW of imports. If California had experienced high demand, the CAISO rules allow it to curtail exports to other regions in order to preserve reliability within California.

The PNW just got by with its own resources during the June scarcity events. If anything had gone wrong with the PNW supply stack – gas pipeline challenges, lower hydro – it is not clear that the PNW neighbors were able to lend a hand.

8.6 Case Study 4: Scarcity Events in Other Regions

It is worthwhile to examine notable scarcity events experienced in other power markets in the United States. While each scarcity event has its own unique circumstances, the common thread involves extreme weather triggering high demand, all types of generators experiencing weather-related challenges or simply not performing, and grid operators scrambling to limit blackouts.

8.6.1 PJM Polar Vortex, January 6-8, 2014

The January 2014 Polar Vortex[49] brought prolonged, deep cold to the entire Mid-Atlantic PJM footprint and surrounding regions. PJM set a new wintertime peak demand record of 141,846 MW the evening of January 7 while dealing with higher-than-normal generation outages.

During the peak demand hour, 22 percent of generation capacity – including coal, gas and nuclear – was out of service. The generation-forced outage rate was two to three times higher than the normal peak winter outage rate of around 7 to 10 percent. Equipment issues associated with both

[49] See "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events" published by PJM. https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf (PJM Report)

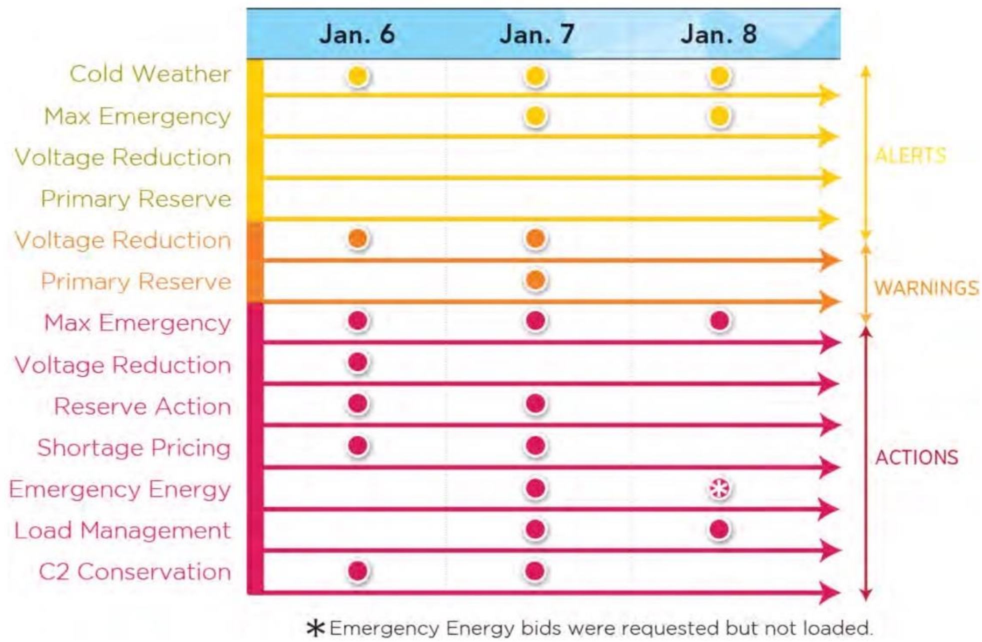
coal and natural gas units caused the greatest proportion of forced outages. Natural gas interruptions comprised approximately 25 percent of the total outages."[50]

Neighboring regions were also experiencing extreme weather and unit outages, and as a result, imports from other balancing authorities were less than one-third of normal levels.

Although operating reserves dipped to dangerously low levels, PJM was able to avoid blackouts. Through a series of planned and orchestrated steps, PJM maintained the necessary reserves. PJM called on all available resources, issued public appeals for conservation, and called on committed demand response capacity.

The figure below, pulled from the PJM Report on the Polar Vortex, shows the series of steps undertaken by PJM to maintain reliability.

Figure 91: Emergency Procedures Taken During the PJM Polar Vortex Scarcity Event [51]



This figure demonstrates a series of alerts, warnings, and actions that stand between scarcity and blackouts.

As a general rule, when "operating reserves" ("primary reserves" plus "synchronous reserves" as shown in next figure) fall below a certain level, the grid operator institutes controlled, rolling blackouts in order to keep ensure sufficient reserves to maintain frequency. On January 7, PJM leveraged every tool in its toolbox – including a Voltage Reduction Action. Voltage reduction incrementally (and temporarily!) reduces demand, typically unbeknownst to the customer, enabling PJM to stretch its limited supply to meet demand and operating reserve requirements.

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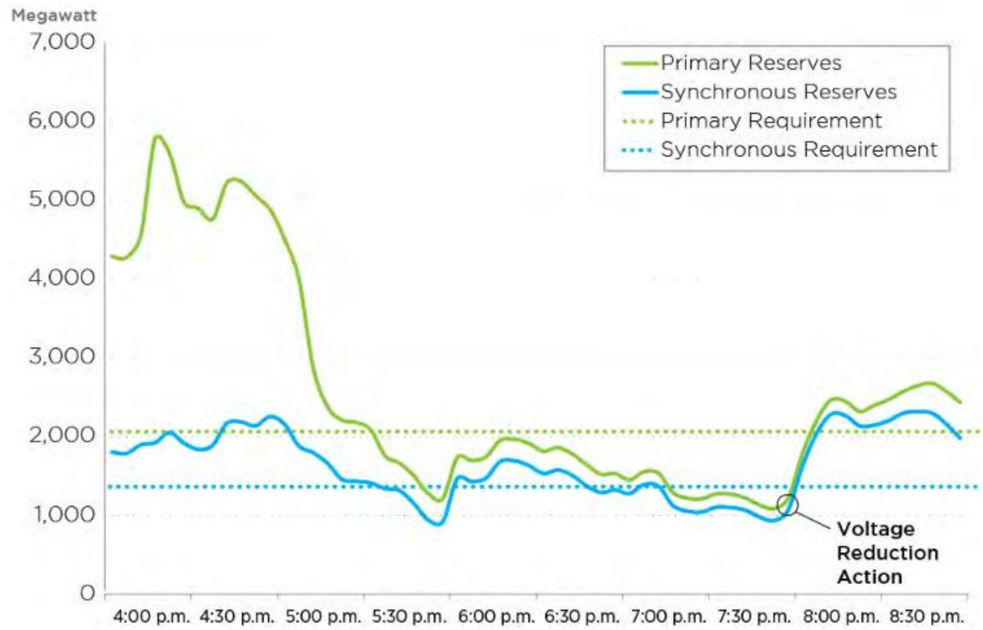
[50] PJM Report p. 4.

[51] Source: "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events" published by PJM. https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf (PJM Report, Figure 5, page 14). Definitions on PJM website: https://emergencyprocedures.pjm.com/ep/pages/messagedefinitions.jsf

The following figure shows how close PJM came to having insufficient reserves.

Figure 92: Voltage Reduction Restores Reserves (Figure 6 from PJM Report)



By 7 pm on January 6, both synchronous and primary reserves had fallen below required levels. PJM implemented voltage reductions which resulted in the necessary increase in operating reserves to avoid controlled blackouts.

After the event, PJM staff studied performance during the Polar Vortex and published the report referenced above. The report concluded with a number of findings and subsequent changes to PJM rules and procedures, including a list of 14 "Lessons Learned and Recommendations". A few of the key findings include:

- Gas/Electric Coordination. Better harmonize the timing of electric and natural gas scheduling procedures. Incorporate natural gas market information into PJM rules related to offer caps and capacity market offers. Increase communication and coordination between electricity market operators and natural gas pipeline/storage operators.
- Fuel-Specific Limitations. Examine difficulties experienced by generators during natural gas emergency procedures. Develop methods to call on long-lead generation if certain resources are fuel constrained.
- Interregional Coordination. Improve coordination of emergency procedures with surrounding balancing authorities.
- Improve Capacity Market Design. Better align capacity market rules and obligations with generator performance during scarcity events.

Like the PNW, many of the challenges faced by PJM are also central to PNW reliability. At the top of the list are the reliance on natural gas deliveries to the power sector under extreme cold conditions and coordination with other regions during scarcity events.

Unlike the PNW, PJM has the advantage of a single, large, centralized market with a single balancing authority (Regional Transmisson Operator, or RTO) and a common set of rules and protocols covering a broad geographic area. The PNW has the Northwest Power Pool (now Western Power Pool), but the capabilities of the power pool to coordinate 10+ individual balancing authorities falls well short of the coordination that is achieved through PJM's RTO structure.

8.6.2 CAISO Blackouts, August 14-15, 2020

California experienced system-wide, rolling blackouts due to lack of supply during the evening hours of August 14 and August 15, 2020. Each day, when solar production declined in the late afternoon, the CAISO found itself with insufficient resources and was forced to implement rolling blackouts. The blackouts amounted to hundreds rather than thousands of MW of load across several hours each day. Yet even these relatively modest load curtailments for short durations captured headlines around the country and shook California's electricity industry.

The CAISO published a comprehensive report entiteld "CAISO Root Cause Analysis" in January 2021 which provides a detailed description of the conditions that led to the rolling blackout.[52] The CAISO identified the following primary factors which contributed to the blackouts:

1. The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.
2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.
3. Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

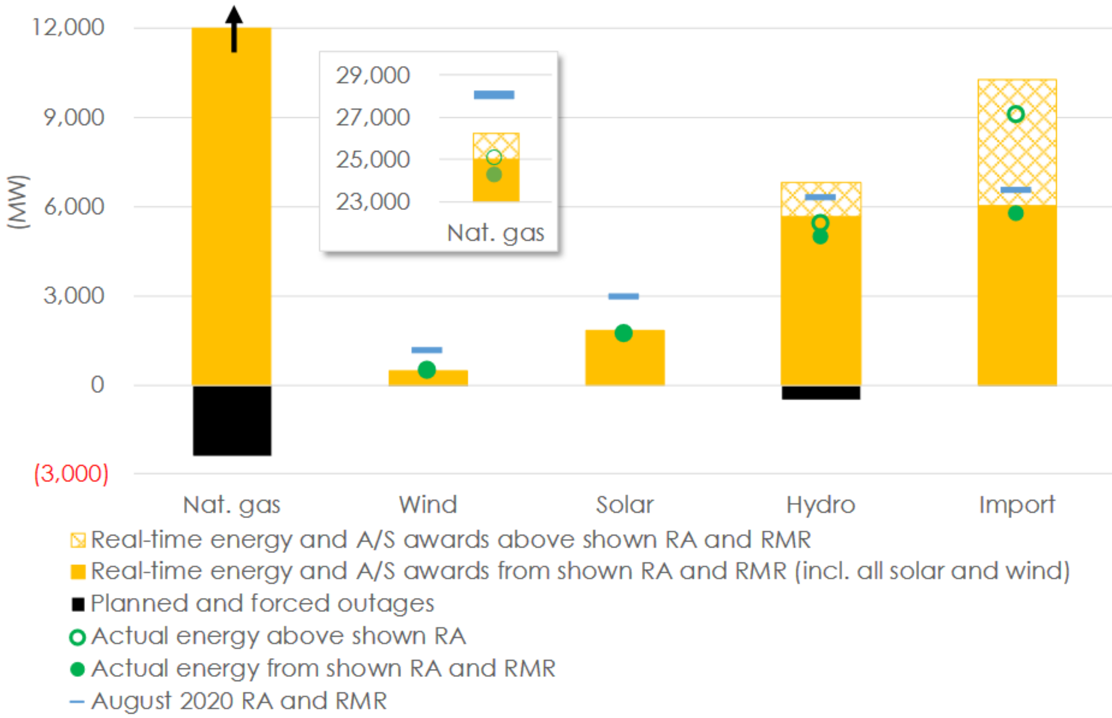
In short, when demand skyrocketed, the CAISO did not have enough of the right supply, and the CAISO itself inadvertently made things worse because they did not have the full awareness of the situation in the day-ahead market.

The next figure, taken from the CAISO Root Cause Analysis, depicts the performance of major resource categories during the blackouts on August 14, 2020.

To understand this graph requires a brief definition of the California Resource Adequacy (RA) program. Under California law, utilities and other load serving entities must procure sufficient supply each year to meet expected peak summer demand, plus a buffer called a "planning reserve margin". Utilities must contract for Resource Adequacy (RA) supply and report or "show" this supply to the CAISO in advance of the summer. The CAISO will have sufficient generation to meet demand if: (1) the load forecast was accurate and (2) the contracted RA supply is available during periods of high demand. On August 14, 2020 neither of these things happened.

[52] Root Cause Analysis Mid-August 2020 Heat Wave" ("CAISO Root Cause Analysis") http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

Figure 93: Comparison of Expected Resource Adequacy Supply and Actual Supply [53]



Let's start by comparing the "Shown" RA to the energy and ancillary services available from these shown resources during the blackouts. The blue dashes are the Shown RA for each resource category. This is the amount of supply that CAISO is counting on to be there. The solid yellow bars reflect the amount of energy and ancillary services provided by **those** Shown RA resources on August 14. The hashed yellow portion of the bars depict energy from non-RA resources (generators with no RA contracts and therefore not shown to the CAISO).

The gap between the Shown RA (blue line) and actual supply (solid yellow) presents supply shortages for the CAISO. Every category of generator was deficient:

- Natural gas plants under-delivered by about 3,000 MW (28k less about 25k)
- Wind and solar had low Shown RA amounts and both under-performed
- Energy from Shown RA hydro and imports came in just slightly low

After accounting for energy from the Shown RA plus extra non-contracted energy, the natural gas fleet, wind, and solar all underperformed while hydro and imports both over-performed.

Like the PNW, during the scarcity events in February and March of 2019, the figure shows that CAISO relied on flexible hydro resources and imports to make up for under-performance in the thermal and renewable fleets.

Unlike the PNW, California utilities have secured about 6,000 MW of import supply through the RA program. That is, 6,000 MW of supply from outside of the state is committed to offering its

[53] Source: CAISO Root Cause Analysis (Figure 4.4, page 46)

supply to California when conditions are tight. Some of this imported supply is tied to contracts with PNW resources.

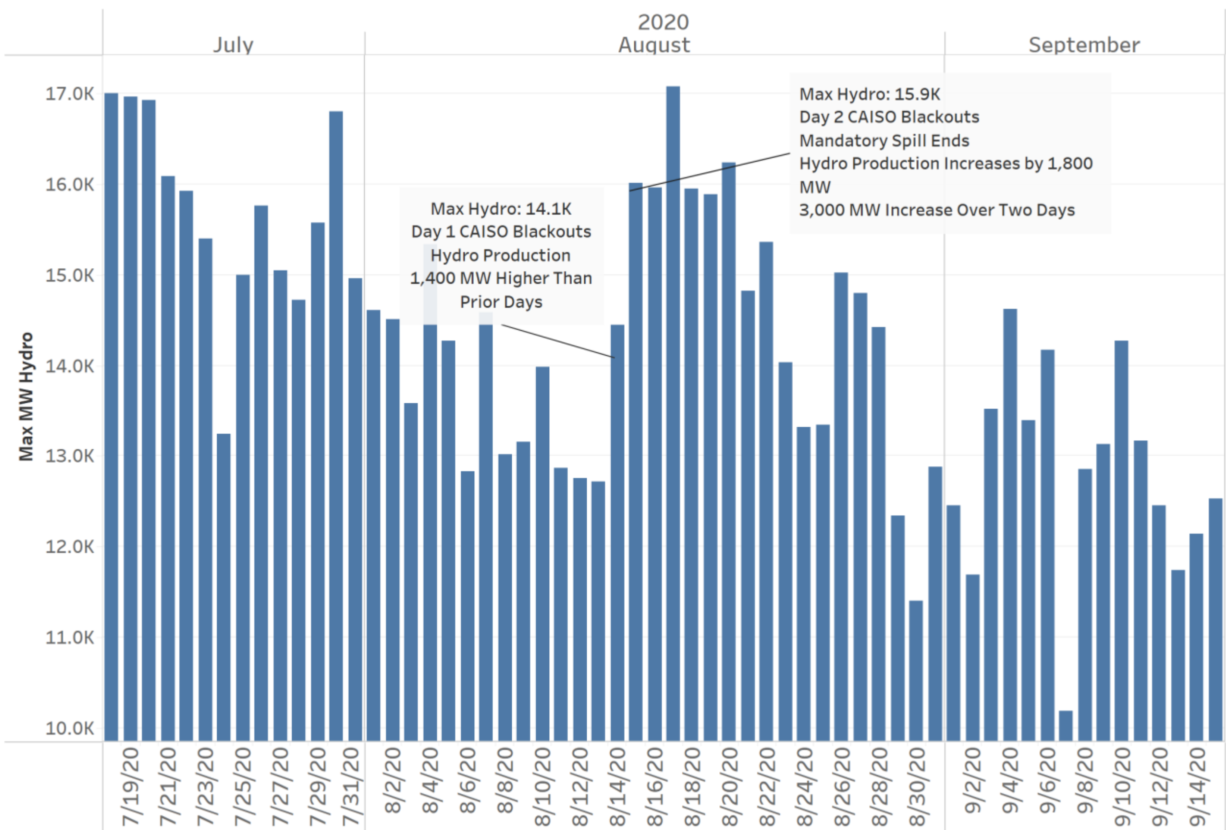
The CAISO report goes on to explain that transmission de-rates up to 650 MW on the California-Oregon Intertie (COI) limited imports from the PNW. With supplies in the PNW healthy at that time, it is possible that blackouts could have been avoided but for a transmission outage on a key transmission line.

During the CAISO August 2020 blackouts, system conditions in the PNW were quite manageable. PNW demand topped out at 21,000 - 23,000 MW, well below the maximum demand levels seen during scarcity events in the region. Mid-C peak prices were $51 per MWh compared to $147 per MWh for Southern California. Natural gas prices were within a normal range. The nuclear and coal fleet were generating close to maximum output and PNW gas units were producing about 1,000 MW below maximum production (5,000 MW of production versus 6,000 MW of capacity).

The Columbia River hydro system does not just provide benefits to the PNW. When California and the Desert Southwest have experienced scarcity events, the PNW hydro system ramped up to support the needs of other regions.

The figure below shows maximum daily PNW hydro output from mid-July to mid-September 2020.

Figure 94: Maximum Daily Hydro Production (MW), July to September 2020

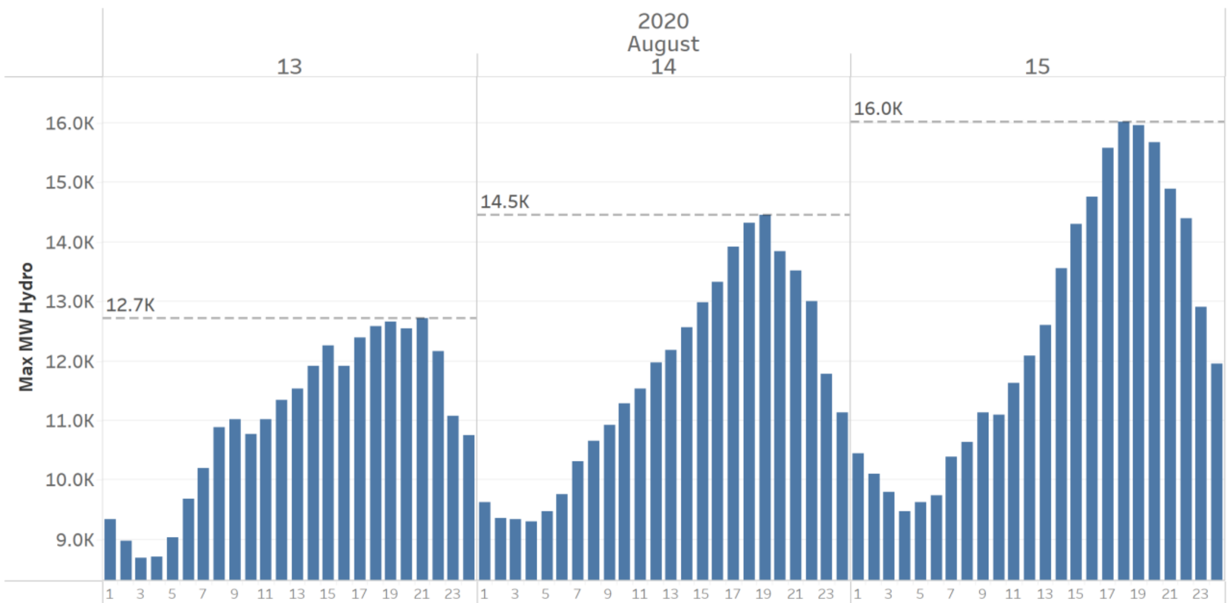


By August, natural inflows into the Columbia River system have declined from the spring runoff. Changes in hydro production – particularly increases in production – are the result of managing water in storage. This includes longer-term storage projects such as Grand Coulee as well as shorter-term pondage distributed across many dams.

On the 14th maximum hydro production ticked up to 14,100 MW – an increase of 1,400 MW from the day before. Note that on the 14th the dams were still under summer spill obligations. On the 15th, maximum hourly hydro output rose to 15,900 MW. This increase was both in response to the rolling blackouts in the CAISO but also because fish spill requirements changed (were lowered) on the 15th of August.

The figure below shows hourly production from PNW dams August 13-15.

Figure 95: PNW Hourly Hydro Production (MW), August 13-15, 2020



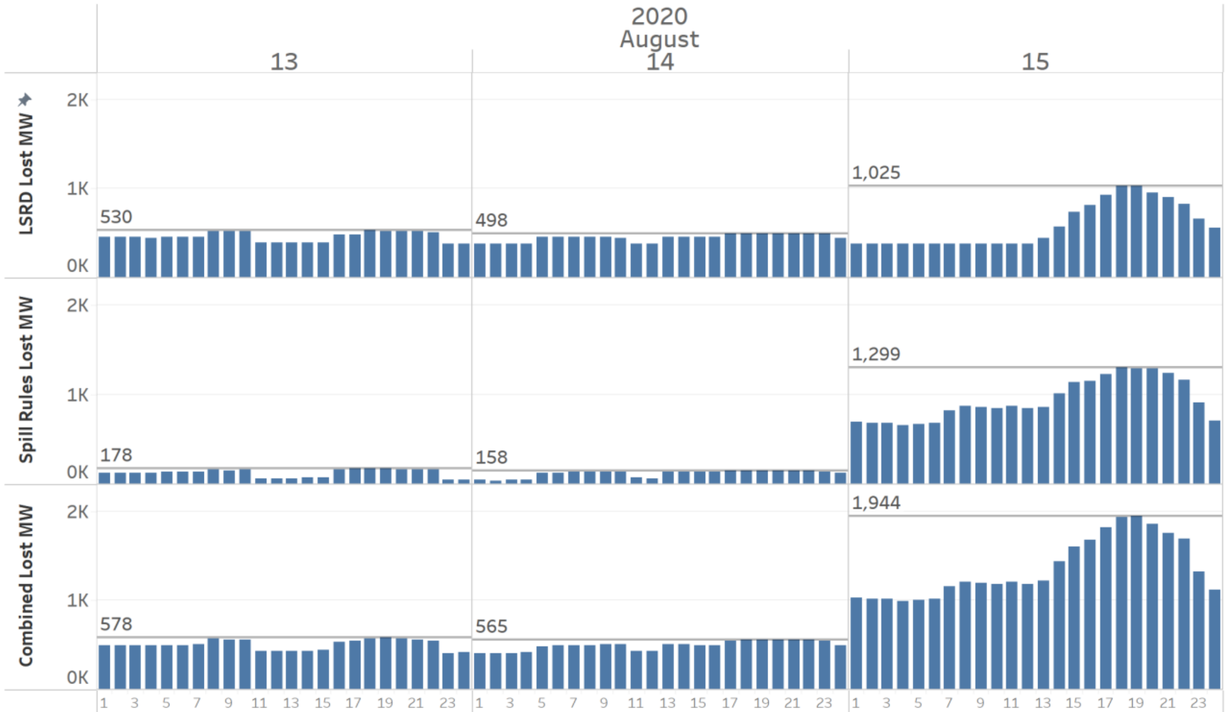
The hydro production is being shaped into the most valuable hours. In California, the need for energy in the summer is most acute between 6 pm and 7 pm as demand is still very high and solar production declines. The PNW hydro system is generating the maximum output during the exact time that the CAISO needs it the most. Had the AC and DC interties been fully operational, it is possible that the PNW hydro could have prevented all or most of the blackouts in CAISO.

Figure 95 shows hourly hydro production that would have been lost due to removal of the LSRD and proposed spill rules for the scarcity event of August 13-15, 2020.

When summer spill rules were in effect through the 14th of August, the lost MW associated with the LSRDs and new spill rules were quite modest, a combined 565 MW. When the summer spill rules ended on August 15, the lost production grew to 1,025 MW for the LSRD, 1,299 MW associated with new proposed spill rules, and a combined amount of 1,944 MW.

With the proposed removal of dams and increased spill obligations, the PNW dams would have produced 1,944 fewer MW during the CAISO blackouts on August 15. This would have likely led to that much less energy being exported to the CAISO during those hours and worsening the magnitude and potentially the duration of blackouts at that time.

Figure 96: Lost Hydro Generation from New Spill Rules and Removal of LSRD (August 2020)



8.6.3 Texas Blackouts During Winter Storm Uri, February 2021

One of the worst electricity blackouts in US history occurred in Texas February 14-19, 2021. The University of Texas at Austin Energy Institute published a report[54] summarizing the causes and impacts of this event:

> *The failure of the electricity and natural gas systems serving Texas before and during Winter Storm Uri in February 2021 had no single cause. While the 2021 storm did not set records for the lowest recorded temperatures in many parts of the state, it caused generation outages and a loss of electricity service to Texas customers several times more severe than winter events leading to electric service disruptions in December 1989 and February 2011. The 2021 event exceeded prior events with respect to both the number and capacity of generation unit outages, the maximum load shed (power demand reduction) and number of customers affected, the lowest experienced grid frequency (indicating a high level of grid instability), the amount of natural gas generation experiencing fuel shortages, and the duration of electric grid operations under emergency conditions associated with load shed and blackout for customers. The financial ramifications of the 2021 event*

[54] "The Timeline and Events of the February 2021 Texas Electric Grid Blackouts", July 2021. https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf

are in the billions of dollars, likely orders of magnitude larger than the financial impacts of the 1989 and 2011 blackouts."[55]

The University of Texas report lists generator outage by category during the blackouts. The figure below from the report shows power plant outages compared to the expected production during February.

Note that Texas has few interconnections with surrounding regions. It is largely an electrical island: a system with peak demand of approximately 75,000 MW has connections with surrounding regions of less than 1,000 MW. In addition, Texas does not have a capacity market or a resource adequacy obligation. Firms were not obligated to deliver the supply. However, grid planners in Texas make estimates of available capacity and these differences are relative to the planners' estimates.

Figure 97: Texas Net Generator Outages and Derates by Fuel Type (MW) [56]

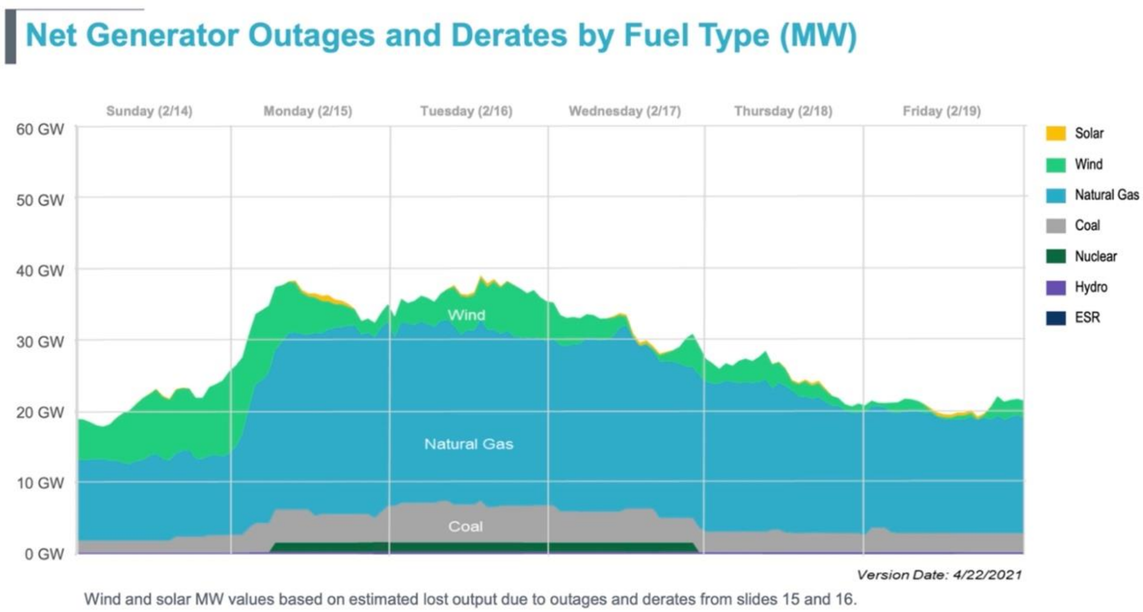


Figure 2.o. Net capacity outages and derates by fuel type, relative to expected contribution from wind and solar. Since wind and solar are not expected to generate at their nameplate capacity rating, the value derating shown here is less than that for wind and solar in Figure 2.n. Figure by ERCOT.[57]

While there were issues across all resource categories, the biggest challenges came from natural gas generation with coal and wind also under-performing. There are a long list of causes and recommendations. Those that are most relevant to the PNW include the following:

- Power plants listed a wide variety of reasons for going offline throughout the event. Reasons for power plant failures include "weather-related" issues (30,000 MW, ~167 units), "equipment issues" (5,600 MW, 146 units), "fuel limitations" (6,700 MW, 131 units),

[55] "The Timeline and Events of the February 2021 Texas Electric Grid Blackouts", July 2021, p. 7.
[56] Source: University of Texas Austin Energy Institute Report, "The Timeline and Events of the February 2021 Texas Electric Grid Blackouts," July 2021 (page 34)

“transmission and substation outages” (1,900 MW, 18 units), and “frequency issues” (1,800 MW, 8 units).

- Failures within the natural gas system exacerbated electricity problems. Natural gas production, storage, and distribution facilities failed to provide the full amount of fuel demanded by natural gas power plants. Failures included direct freezing of natural gas equipment and failing to inform their electric utilities of critical electrically-driven components. Dry gas production dropped 85% from early February to February 16, with up to two-thirds of processing plants in the Permian Basin experiencing an outage.
- Natural gas in storage was limited. Underground natural gas storage facilities were operating at maximum withdrawal rates and reached unprecedently-low levels of working gas, indicating that the storage system was pushed to its maximum capability.

8.6.4 Case Study 4 Conclusion

Scarcity events throughout the United States have similar underlying causes. Of course, high demand is always a starting point.

This high demand comes from increasingly common extreme weather events. Each of these weather events was between a 1-in-10-year to a 1-in-30-year event. With climate change, these events will almost certainly become more common.

A common theme across PJM, CAISO, and ERCOT – and the PNW – is challenges with natural gas supply and generation. As the largest source of generation on each of these grids, it isn’t surprising that natural gas played a central role in blackouts or near blackouts. There are two features of natural gas supply that pose difficult challenges for the electricity grid: (1) Winter heating demand is met with both electricity and natural gas. During winter cold events, demand for electricity increases at the exact time that natural gas is in short supply. (2) Natural gas supply is not stored on-site for electricity generation. This is different than coal, nuclear, or oil-fired generation. As such, any disruptions to the natural gas delivery system immediately constrain the natural gas generators. There is little room for error. During weather-driven scarcity events, the natural gas systems are very often under duress as well.

Another theme in Texas and California relates to the challenges of ever-larger renewable portfolios. While renewables were not the primary driver (or the biggest culprit) in either the Texas or California blackouts, the renewable fleet under-performed relative to obligations or expectations in both cases. As the renewable fleets grow to meet ever-increasing RPS targets, the issue of renewable performance during extreme demand events will only grow in importance.

With regards to imports, for Texas and PJM, there was little supply available from surrounding regions (PJM) or few interconnections with surrounding regions (Texas). The CAISO relied heavily on voluntary imports to limit the magnitude of blackouts.

These national case studies punctuate the importance of these same issues and concerns for the PNW. The winter of 2019 PNW scarcity events were exacerbated by limited access to natural gas. Renewables have under-performed in all PNW scarcity events. The PNW has relied on un-contracted, voluntary imports to balance supply and demand: should the CAISO and the PNW both need imports at the same time, California has contracted for certain PNW resources via its

RA procurements while the PNW has no RA markets and relies almost entirely on voluntary imports.

The PNW hydro system remains the bedrock of reliability, providing carbon-free, local, reliable, flexible supply with a track record of strong performance during scarcity events.

8.7 Scarcity Event Case Studies Conclusions

The results of the case studies are summarized in the table below.

Table 5: Summary of Scarcity Event Case Study Analysis

	Case 1 Feb 2019	Case 2 Mar 2019	Case 3 Jun 2021	PJM Polar Vortex Jan 2014	CAISO Blackouts Aug 2020	Texas Blackouts Feb 2021
Trigger	Cold snap	Cold snap	Heat dome	Cold snap	Heat	Winter storm Uri
Mid-C Price	$138	$890	$334	n/a	$51	n/a
PNW Demand	29,500 MW	27,300 MW	28,400 MW	n/a	24,700 MW	n/a
Baseload (Coal and Nuclear)	Performed well	Performed well	Still some outages	Generator outages	Nuclear performed well.	Under-performed
Natural Gas	4,600 MW Limited: supply competed with heating needs	3,400 MW Limited: supply competed with heating needs	4,200 MW Limited: generator outages	Generator outages and supply issues	Under-performed	Failures throughout the natural gas supply and generation systems
Imports	+6,000 MW. Record import level.	+4,500 MW.	+1,600 MW.	Under-delivered	PNW Exported Under-delivered: transmission de-rated	n/a: few interconnections to Texas grid
Renewables	Extreme low wind event	Extreme low wind event	Low wind event	n/a	Under-performed	Underperformed
Hydro Max	16,700 MW	15,600 MW	17,100 MW	n/a	17,082	n/a
Hydro Daily Flex	7,200 MW	5,900 MW	3,200 MW	n/a	6,600 MW	n/a
Proposed Policies: Lost Hydro Capacity	-1,700 MW (combined)	-1,778 MW (combined)	-992 MW (combined)	n/a	-1,944 MW (combined)	n/a

The vulnerabilities of each leg of the supply stack reveal themselves in this summary.

- **Natural Gas Generation** is vulnerable to supply constraints and delivery risks, and in the winter, heating demand takes priority over electricity generation. For example, in the scarcity event of March 2019 the natural gas fleet generated only 3,400 MW out of maximum capacity of 5,900 MW.

- **Imports** into the PNW region varied greatly from one scarcity event to the next. The record-setting level of imports in February 2019 likely kept the lights on in the PNW. Imports were only 1,600 MW during the heat dome event in June 2021 with little help coming from British Columbia or the East side. It required prices to rise above $300 per MWh to attract imports from California.
- **Renewables** in the BPA service territory performed extremely poorly during the winter of 2019 and poorly during the heat dome in 2021. Renewables simply can't be counted on to help during extreme events.
- **Baseload Resources** performed well. However, with coal retirements in the PNW and in the broader region, this portion of the supply portfolio will continue to shrink, which will impact both in-region resources and available imports.

In many ways, it is often luck which determines which challenges hit the grid during any given scarcity event. It is easy to see how the February 2019 scarcity event could have been much worse with the following adjustments:

-1,300 MW of baseload coal generation due to Centralia and Boardman retirement
-1,200 MW of natural gas generation if supply constraints existed as in March 2019
-1,700 MW of lost hydro production due to policy changes
-4,200 MW total less supply compared to February 2019

This level of scarcity is unprecedented. Where will the extra MW come from?

- The coal units have retired, there is no bringing those back.
- Natural gas plants are vulnerable to supply constraints, and there is currently no additional natural gas supply.
- Once removed, you can't bring the LSRD back either.
- To balance the PNW grid, imports would have to increase from 6,000 MW to 10,200 MW. In February 2019 the PNW maintained reliability via 6,000 MW of imports, and this level of imports shattered all previous records of imported energy. As discussed above, most of these imports came from the East side, a region which will experience significant coal retirements in the coming years. There is currently no mechanism to ensure that this happens and the PNW has no contractual rights to that level of imported energy. Indeed, we are already seeing circumstances where this level of power may not be available from other regions at any price during times of scarcity. If this set of plausible circumstances came to bear, there is a strong possibility that a scarcity event turns into a blackout.

There are a variety of other ways that the supply and demand "cards" could be "re-shuffled": greater demand due to more extreme weather, higher levels of natural gas outages due to pipeline constraints, limited access to imports due to wildfire risk, or fewer thermal resources as coal plants retire.

The only supply resources that flex to meet demand are imports and hydro. While imports are an invaluable option when one region is experiencing a scarcity event, their usefulness breaks down when scarcity is occurring across multiple regions, and the PNW has not contracted any import obligations like other regions who have a Resource Adequacy Program. There is no guarantee that imports will be available for future events – regardless of contracts, the risks of extreme weather and wildfire are piling up the risks to transmission availability with climate change. Imports are only available if the surrounding regions are not also experiencing scarcity – and there is strong evidence that many regions of the WECC are experiencing scarcity. No price signal is high enough to draw in extra power from other regions if that extra power doesn't exist.

Should the PNW also lose access to certain hydro resources due to increased spill obligations or removal of the LSRD, the picture begins to look bleak in terms of meeting demand during these extreme events. The Western scarcity events, though occurring during different seasons and under different sets of supply and demand conditions, have one major thread in common: during the times of highest need, the hydro resources were the main ones available to provide large amounts of flexible generation, not only to the PNW but to the WECC more broadly.

It's hard to envision these factors becoming less important in the future. Thermal and nuclear plants are slated for retirement over the coming years. While they'll be replaced by renewables, even renewables co-located with storage aren't currently equipped to serve scarcity events that can last for days on end, especially when the weather conditions during these events often aren't conducive to renewable resources showing up.

Extreme weather events, and hence extreme demand events, are forecasted to become more common with climate change. The need for large quantities of flexible generation to serve unexpectedly high demand isn't going to go away. In the past, the main resource to fulfill this need has been hydro. The loss of generation that would result from breaching the LSRD and increasing the spill requirements would mean a significant loss of reliability during the times when, historically, it's been needed the most.

9 Summary and Conclusions

The PNW has electricity policies that are aspirational and laudable – the creation of carbon-free supply resources to meet 100% of demand in the next 20 years. These policies will require the build-out of unprecedented amounts of renewables and storage and retiring coal plants across the region, which reduces reliable supply during scarcity events.

Yet on a parallel path, some policy makers would like to reduce production from the PNW's largest energy supplier and carbon-free resource, hydro, by increasing spill operations and removing the LSRD to support salmon survival. While this is a noble goal, the diminished hydro fleet will remove carbon-free energy from the grid and all-important flexible capacity which may be required during scarcity events.

9.1 Analysis Summary

The purpose of this analysis was to estimate the energy and capacity impacts of proposed policies to improve salmon recovery, estimate the increased carbon emissions, estimate the direct, short-term, financial costs stemming from those policies, and provide real-world data and examples of the potential reliability implications.

In section 6, we estimated the energy and capacity impacts of the proposed policies. In section 7, we estimated carbon emissions and short-term financial costs. The results of both analyses are summarized in the table below:

Table 6: One-Year Impacts on Lost Resources, Costs, and Carbon Emissions

	Units	One Year 2023 Cost Increased Spill	One Year 2023 Cost LSRD Removal	One Year 2023 Cost LSRD Spill + LSRD
Energy Value				
ICE Price All Hours	$/MWh	$66.49	$66.49	$66.49
Volume-Weighted Value	$/MWh	$58.80	$60.90	$61.21
Avg Lost Energy	MW	435	919	1133
Replacement MWh	MWh	3,808,066	8,048,174	9,923,614
Replacement Energy $	$	**$223,899,194**	**$490,160,831**	**$607,414,401**
Capacity Value				
Lost Winter Capacity	MW	515	2,284	2,556
Lost Summer Capacity	MW	930	1,644	1,809
Replacement Capacity	MW	723	1964	2183
Capacity Price	$/kW-Mo	$7.00	$7.00	$7.00
Replacement Capacity $	$	**$60,690,000**	**$164,976,000**	**$183,330,000**
2023 Replacment Cost	$	**$284,589,194**	**$655,136,831**	**$790,744,401**
Increased CO2 Emissions	Tons	**1,629,852**	**3,444,618**	**4,247,307**

Replacement Capacity Estimates Max Lost Winter and Max Lost Summer Capacity

ICE Price All Hours Based on Forward Market Prices Published by the InterContinental Exchange (ICE)

Capacity Price Based on Recent WECC Capacity Price Quotes from Brokers

Carbon emissions assume 0.428 tons of carbon per MWh of electricity

In section 8, we examined three scarcity events in the PNW, blackouts in California, and challenges faced by PJM and ERCOT. The conclusions from these case studies are sobering:

- Natural gas generation was vulnerable to supply constraints and delivery risks, and in the winter, heating demand took priority over electricity generation.
- Imports into the PNW region varied greatly from one scarcity event to the next. Record-setting level of imports in February 2019 likely kept the lights on in the PNW. Imports were harder to come by and more expensive during the one summer scarcity event.
- Renewables in the BPA service territory performed poorly during all scarcity events. They simply can't be counted on to help during extreme events.
- Baseload resources performed well. However, with coal retirements this portion of the supply portfolio will continue to shrink, impacting both in-region resources and available imports.

It's hard to envision these scarcity event factors becoming less important in the future. The conditions are present in the PNW for scarcity events to potentially escalate into blackouts. This risk gets worse when hydro supply is removed from the generation fleet.

If it were possible to build natural gas plants (or other dispatchable resources with fuel supplies) to replace lost hydro capacity, the reliability concerns might be low. The reliability of gas plants could even be bolstered through dual fuel capabilities and on-site oil storage. But current policy calls for elimination of fossil fuels – not the addition.

The analysis strongly suggests that costs associated with the proposed policies will be high. With an electric grid that is already prone to scarcity events, removal of the LSRD or implementation of both policies may very well prove to a tipping point, nudging the PNW system into acute scarcity.

There are a number of other results which are harder to handicap and harder to value. These include higher overall electricity prices due to more scarcity events and increased risk that scarcity events will lead to blackouts. These costs can be significant and society-wide as opposed to just borne by BPA and its customers.

9.2 Conclusions and Recommendations

While this is not policy paper which delineates fixes that would be helpful to mitigate the issues raised, in this paper there were several key ideas discussed that are worth revisiting briefly:

9.2.1 Understand the Risks Facing the PNW

As discussed throughout this paper, the risks already facing the PNW electricity grid are significant. These include:

- An already-existing state of scarcity, and neighboring regions facing similar constraints
- Retirement of coal resources further exacerbating capacity shortages
- Forest fires posing new challenges for the transmission system

- Natural gas delivery risks, with inadequate storage and few delivery pipelines
- Growing electricity demand, fueled by a proliferation of data centers and bitcoin mining operations, and state policies that support the electrification of previously non-electric activities, such as transportation, cooking, and heating
- Climate change adding extreme weather events into the mix

9.2.2 Realize the Electricity System Implications of the Proposed Policy Changes

The implications of spill policies and removal of the LSRD are very different:

- Spill policies can be designed to remove energy (shifting water from turbines to spillways) while still leaving flexibility to reduce spill during scarcity events to prevent blackouts. While there are costs associated with replacing the spilled energy, and the replacement energy will lead to increased carbon emissions, these costs can be readily quantified if one chooses to do the math.
- The removal of the LSRD is a different proposal entirely: Once gone, the dams will not come back.
- Both policies implemented together will have a greater magnitude of impacts, and should be considered in light of each other

9.2.3 Prioritize the Western Resource Adequacy Program

The Western Power Pool (previously the Northwest Power Pool) is in the process of launching a Western Resource Adequacy Program.[57] The purpose of a Resource Adequacy Program is to develop a common way to "do the math" of total resource capacity and ensure that utilities have procured sufficient resources to meet demand plus a planning reserve margin. Once that program is up and running, we should have a much better understanding of the capacity needs in the PNW.

As it stands today, each balancing authority (e.g., utility) creates its own standards and procures its own resources to meet its own self-determined standard, which creates inherent inefficiencies. Today, there is no entity that ensures that totality of the individual plans equate to a grid that achieves the desired level of reliability.

In California, CAISO has already implemented a Resource Adequacy Program, and one of the results was the procurement of contractually-obligated imports for scarcity events and times of need. This could be a benefit of a Western Resource Adequacy Program because currently the PNW instead relies on voluntary import supply through market pricing.

If the Western Resource Adequacy Program indeed launches in the next couple of years, it would be best situated to model and opine on the reliability implications of spill rules and LSRD removal.

9.2.4 Invest in Major Transmission Infrastructure

The PNW will very quickly exhaust renewable resources that are proximal to the existing transmission system (which, as discussed earlier, was physically located to accommodate the

[57] https://www.westernpowerpool.org/about/workgroups/12

dams on the river system). To achieve high renewable penetration rates, as is called for by State policies, renewables will have to be developed further away and brought to the region via new transmission lines. Thoughtful coordination between resource planning and transmission needs will be required to achieve lofty RPS targets.

Serious consideration of removal of the LSRD must be informed by the need for new transmission lines and an understanding of the challenges associated with permitting, financing, and constructing new transmission facilities.

9.2.5 Protect the Grid with Wildfire Preparedness

Widespread wildfires and the growing impact of these fires on electricity infrastructure has become increasingly important in the last decade. Individual utilities as well as those in the reliability business (e.g., Western Electricity Coordinating Council) are focused on this issue now.

An area that has to be advanced is the interplay between wildfire risk, resulting transmission outages, impacts on reliability, and the generation resource decisions that should be informed by all of this analysis. The PNW, and the rest of the Western power grid, has immense exposure to wildfire risk and these risks must be fully understood.

9.2.6 Plan for Natural Gas Infrastructure

The most notable blackouts or near-blackouts in the last twenty years involved failures in the natural gas generation fleet.

In the California blackouts of 2020, it was an accounting failure: the State regulators gave gas plants too much capacity credit for resources that they knew would be de-rated with high temperatures in the summer. In ERCOT, PJM, and the PNW the failures had to do with the inability to deliver natural gas to power plants during scarcity events. This is a well-studied issue by numerous utilities in the West. Prior to the issues in Texas in 2021, ERCOT had a similar event in 2011. Despite full knowledge about what should be done to remedy the problems, Texas chose to relive them in 2021.

If the PNW is going to remove hydro capacity from the fleet, they should ensure that all available steps have been taken to firm up the capabilities of the natural gas generation fleet.

9.2.7 Create an RTO Market

FERC Order 2000, issued in 1999, called on transmission providers to organize into centralized markets run by Regional Transmission Organizations (RTOs). More than 20 years have passed, and the PNW has not made significant steps towards formation of an RTO.

An RTO allows for easier integration of renewables, better coordination of the transmission grid, and takes advantage of efficiently dispatching and moving electricity across a broad geographic region.

RTO's typically play a role in establishing Resource Adequacy Program rules as well. If the region wishes to pursue a high renewable, low carbon future, the formation of an RTO should be a top priority.

9.2.8 Define the Opportunities and Limitations of Battery Storage

The PNW region has little experience with battery storage, yet the current model for achieving RPS targets is a combination of new renewables plus battery storage.

The capacity value of battery storage is still being debated. For example, there are studies that conclude that the capacity value of a 100 MW battery with four hours of storage should be as high as 80 MW while other analyses peg the number much lower, closer to 20 MW. This is a meaningful difference: 4x.

Removing dispatchable resources—whether coal, natural gas, or hydro—and replacing these resources with batteries means the planners better have a good idea of how many batteries are required to achieve the same level of reliability. Until that question gets resolved, it is hard to plan for a future where energy comes from renewables and reliability comes from battery storage.

10 Appendix A: Modeled Injunction Spill Operations

	Spring Spill Season		Summer Spill Season	Fall/Winter Spill Season		
Project	Injunction Operation	Gas Cap Spill Proxy From 2021 Spill Cap Reports	Injunction Operation	Injunction Operation	Proxy	Minimum Turbine Flow From 2021 FOP (KCFS)
Lower Granite	125% Gas Cap Spill	79-81 KCFS based on Month	18 KCFS	Surface-oriented spill	See Offseason Tab	11.8-12.9
Little Goose	125% Gas Cap Spill 16 hrs/day, "performance spill" for 8 daytime hours	81 KCFS	30%	Surface-oriented spill	See Offseason Tab	11.3-11.8
Lower Monumental	125% Gas Cap Spill	106 KCFS	17 KCFS	Surface-oriented spill	See Offseason Tab	11.1-12.3
Ice Harbor	125% Gas Cap Spill	114 KCFS	45KCFS	Surface-oriented spill	See Offseason Tab	8.4-10.1
McNary	125% Gas Cap Spill	260 KCFS	57%	Surface-oriented spill	See Offseason Tab	50-60
John Day	125% Gas Cap Spill	190 KCFS (est)	40%	Surface-oriented spill	See Offseason Tab	50-60
The Dalles	40% spill up to Gas cap spill	40%	40%	Surface-oriented spill	See Offseason Tab	50-60
Bonneville	125% Gas Cap Spill, not to exceed 150 kcfs	150 KCFS	95 KFS	Surface-oriented spill	See Offseason Tab	50-60

	Spring Spill Season	Summer Spill Season	Fall/Winter
Lower Snake	April 3 - June 20	June 21 - August 31	September 1 - April 2
Lower Columbia	April 10 - June 15	June 16 - August 31	September 1 - April 9

Source

Injunction Operations	Oregon PI Motion
Spring Spill Proxy Values	2021 Spill Cap Report Max FOP Spill http://pweb.crohms.org/tmt/documents/ops/spill/caps/
Minimum Turbine Flow	2021 Fish Passage Plan Apendix E Generally Assumed Min Flow for Unit 1

Table 1: Injunction spill operation			
Project	**Apr. 3 (LSR)/Apr.10 (LCR) through June 20 (LSR)/June 15 (LCR) ("Spring spill season") for 24 hours per day/7 days per week**	**June 21 (LSR)/June 16 (LCR) through August 31 ("Summer spill season") for 24 hours per day/7 days per week**	**September 1 through April 2 (LSR)/April 9 (LCR; "Fall/Winter spill season") for 24 hours per day/7 days per week**
Lower Granite	125% Gas Cap spill	18 kcfs	Surface-oriented spill (Full operation of Bay 1 Removable Spillway Weir (RSW))
Little Goose	125% Gas Cap spill for 16 hours per day; "Performance spill" levels for 8 daytime hours per day as specified in FPP.	30%	Surface-oriented spill (Maximum operation of Bay 1 Adjustable Spillway Weir high crest)
Lower Monumental	125% Gas Cap spill	17 kcfs	Surface-oriented spill (Full operation of Bay 8 RSW)
Ice Harbor	125% Gas Cap spill	45 kcfs	Surface-oriented spill (Full operation of Bay 2 RSW)
McNary	125% Gas Cap spill	57%	Surface-oriented spill (Full operation of Temporary Spillway Weirs (TSW) in Bay 19 and Bay 20)
John Day	125% Gas Cap spill	40%	Surface-oriented spill (Full operation of TSWs in Bay 18 and Bay 19)
The Dalles	40% spill up to Gas cap spill (Gas cap fish passage spill restricted to spillbays 1-8)	40%	Surface-oriented spill (Open Ice & Trash Sluiceway (ITS) End Gate and OPEN Sluice gates 1-1, 1-2, 1-3 & 18-1, 18-2, 18-3)
Bonneville	125% Gas Cap spill, not to exceed 150 kcfs	95 kcfs	Surface-oriented spill (Powerhouse Two Corner Collector (B2CC), Powerhouse 1 (PH1) ITS, and Bays 1 & 18)

11 Appendix B: Generation Fleet

The tables in the appendix list the generation fleet used in the analysis or other generation fleet data as supplemental materials.

Table 7. Coal retirement assumptions for the NWPP. Source: EIA, NWPP, EGPSC.

Name	Nameplate Capacity	Retirement Date	Generator	State
Comanche (CO)	383	12/1/2022	1	CO
Martin Drake	75	12/1/2022	6	CO
Martin Drake	132	12/1/2022	7	CO
Jim Bridger	608	12/31/2023	1	WY
North Valmy	290	12/1/2025	2	NV
North Valmy	277	12/1/2025	1	NV
Centralia	730	12/1/2025	2	WA
Comanche (CO)	396	12/1/2025	2	CO
Craig (CO)	446	12/1/2025	1	CO
Naughton	256	12/31/2025	2	WY
Naughton	384	12/31/2025	3	WY
Naughton	192	12/31/2025	1	WY
Neil Simpson II	90	12/31/2025	2	WY
Dave Johnston	255	1/1/2027	3	WY
Hayden	275	12/1/2027	2	CO
Dave Johnston	134	12/31/2027	2	WY
Dave Johnston	400	12/31/2027	4	WY
Dave Johnston	134	12/31/2027	1	WY
Craig (CO)	446	9/1/2028	2	CO
Hayden	190	12/1/2028	1	CO
Jim Bridger	617	12/31/2028	2	WY
Pawnee	552	12/31/2028	1	CO
Rawhide	294	12/1/2029	1	CO
Craig (CO)	535	12/1/2029	3	CO
Ray D Nixon	207	12/1/2029	1	CO
Bonanza	500	12/1/2030	1	UT
Wygen 1	90	12/31/2032	1	WY
Laramie River Station	570	12/31/2033	3	WY
Huntington	496	12/31/2036	2	UT
Huntington	541	12/31/2036	1	UT
Jim Bridger	608	12/31/2037	3	WY
Jim Bridger	608	12/31/2037	4	WY
Colstrip	824	12/31/2037	4	MT
Colstrip	824	12/31/2037	3	MT
Colstrip Energy LP	46	12/31/2037	GEN1	MT
Hunter	525	12/31/2038	1	UT
Hunter	525	12/31/2038	2	UT
Hunter	527	12/31/2038	3	UT
Wyodak	402	12/31/2039	1	WY

Table 8. EGPSC Hydro Facilities in the hourly production database.

Name	Capacity	State
Alder	42	WA
Albeni Falls	42	ID
Big Cliff	21	OR
Bonneville	1,154	OR
Boundary	1,104	WA
Box Canyon	90	WA
Brownlee	727	ID
Cabinet Gorge	295	ID
Cougar	26	OR
Chelan	62	WA
Chief Joseph	2,410	WA
Cowlitz Falls	70	WA
Detroit	100	OR
Dexter	15	OR
Diablo	182	WA
Dworshak	400	ID
Electron	26	WA
Foster	20	OR
Grand Coulee	6,765	WA
Green Peter	80	OR
Hills Creek	30	OR
Hells Canyon	445	OR
Hungry Horse	428	MT
Ice Harbor	523	WA
H M Jackson	104	WA
John Day	1,923	OR
Selis Ksanka Qlispe	28	MT
LaGrande	64	WA
Lower Baker	105	WA
Little Falls (WA)	43	WA
Little Goose	675	WA
Libby	525	MT
Lower Monumental	752	WA
Long Lake	90	WA
Lookout Point	80	OR
Lost Creek	49	OR
Lower Granite	802	WA
Mayfield	164	WA
McNary	969	OR

Name	Capacity	State
Merwin	151	WA
Mossyrock	322	WA
Nine Mile	38	WA
Noxon Rapids	623	MT
Oxbow (OR)	220	OR
Pelton	110	OR
Priest Rapids	950	WA
Rock Island	458	WA
Ross	450	WA
Round Butte	353	OR
Rocky Reach	1,254	WA
Snoqualmie	12	WA
Snoqualmie 2	34	WA
Swift 1	264	WA
The Dalles	1,766	OR
Thompson Falls	94	MT
Upper Baker	105	WA
Wanapum	1,220	WA
Wells	756	WA
Yale	164	WA

Table 9. List of Thermal Plants Used in the Analysis.

Facility Name	Winter Capacity (MW)	State
Beaver	541	OR
Bennett Mountain Power Project	197	ID
Boardman	585	OR
Carty Generating Station	281	OR
Centralia	1,340	WA
Chehalis Generation Facility	340	WA
Colstrip	2,094	MT
Coyote Springs	394	OR
Dave Gates Generating Station	144	MT
Encogen Generating Station	183	WA
Evander Andrews Power Complex	299	ID
Ferndale Generating Station	286	WA

Facility Name	Winter Capacity (MW)	State
Frederickson	162	WA
Frederickson Power LP	180	WA
Fredonia	228	WA
Fredonia Generating Station	120	WA
Goldendale Generating Station	194	WA
Grays Harbor Energy Center	378	WA
Hardin Generating Station	107	MT
Hermiston	320	OR
Hermiston Power Plant	390	OR
Klamath Cogeneration Project	368	OR
Klamath Generation Peakers	115	OR
Langley Gulch Power Plant	197	ID
March Point Cogeneration	138	WA
Mill Creek Generating Station	144	MT
Mint Farm Generating Station	207	WA
Northeast (WA)	66	WA
Port Westward	268	OR
Port Westward Unit 2	224	OR
Rathdrum Combustion Turbine Project	175	ID
Rathdrum Power, LLC	172	ID
River Road	248	WA
Sumas Generating Station	137	WA
Whitehorn	162	WA