EXH. PKW-4
DOCKET UE-20____
2019 PCA PERIOD COMPLIANCE FILING
WITNESS: PAUL K. WETHERBEE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of **PUGET SOUND ENERGY** **For Approval of its 2020 Power Cost Adjustment Mechanism Report**	**DOCKET UE-20____**

THIRD EXHIBIT (NONCONFIDENTIAL) TO
THE PREFILED DIRECT TESTIMONY OF

PAUL K. WETHERBEE

ON BEHALF OF PUGET SOUND ENERGY

APRIL 30, 2020

Pricing Event of March 2019—System Impact Assessment

August 20, 2019

Executive Summary

From March 1 to March 4, 2019, the Pacific Northwest (PNW) and western Canada experienced unusually high prices for natural gas and electric power. During that time, power was being traded at prices nearing $1,000 per MWh. WECC assessed the event to determine the role of, and implications to, system reliability. An advisory group made up of WECC staff and members of the WECC Operating Committee (OC) and Market Interface Committee (MIC) came to the following conclusion:

> While the March 2019 pricing event did not erode electric system reliability, it is likely that changing system composition and circumstances will create the conditions for this type of event to happen again, perhaps with direct impacts to the reliability and security of the bulk power system (BPS). Similar events may happen more often as low capacity-factor variable generation resources replace high capacity-factor, base-load generation.

The team based its conclusion on the following observations:

- Efforts to maintain the reliability of the BPS did not contribute to the increased prices.
- The increase in natural gas prices affected the electric power prices; however, the price increase did not impact the reliability of the BPS.
- No Load-Serving Entities (LSE) or Balancing Authorities (BA) interrupted load due to a lack of electric power.
- During the event, there were enough operating reserves to keep the system stable, and Peak Reliability did not declare any Energy Emergency Alerts.
- Several factors—like reduced transmission availability, long-term cold temperatures, and low hydro generation availability—contributed to the increase in prices, though none of these factors alone could have caused the event.

Recommendations

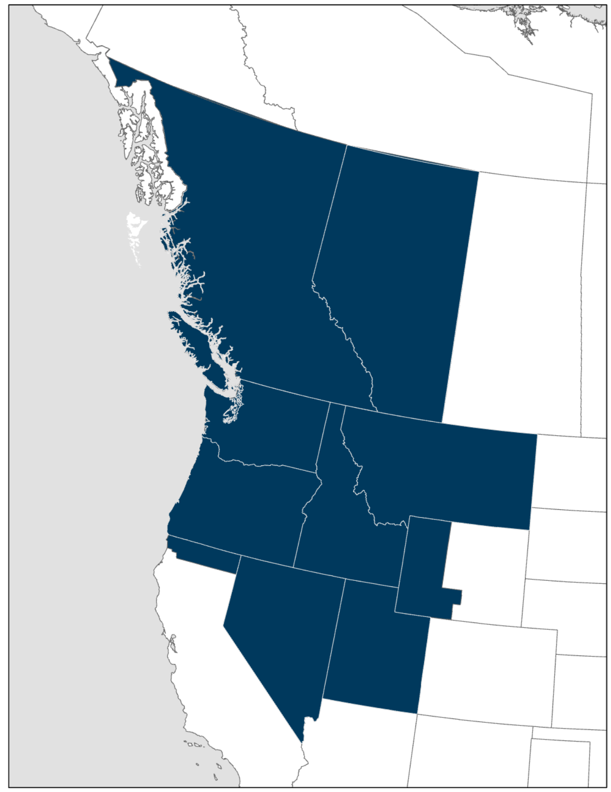
Recommendation 1—As states continue to apply requirements for low- or zero-carbon power generation, LSEs and BAs must plan for extreme weather scenarios to ensure enough generation and transmission resources are available to serve demand under all conditions.

Recommendation 2—Transmission and generation owners and operators and BAs should reevaluate their maintenance practices in coordination with Reliability Coordinators (RC) to make sure enough resources are available to cover demand under all conditions.

Recommendation 3—Industry should standardize the way in which fuel-limited resources are reported for contingency reserves to ensure BAs and RCs know to what degree and for how long the reserves can cover demand.

Recommendation 4—WECC, LSEs, and BAs should analyze the capability of the Western Interconnection to meet demand under extreme weather conditions. WECC, LSEs, and BAs must perform various studies, including Power Flow, Generation Resource Adequacy, and Transmission Resource Adequacy. These studies should focus on the anticipated increase in low capacity-factor wind and solar resources that are expected to replace high capacity-factor coal and natural gas-fired generation.

Introduction



The PNW and western Canada experienced high prices for natural gas and electric power from March 1 to 4, 2019, during which power was being traded at nearly $1,000 per MWh. While this was a pricing event, the extreme energy prices prompted WECC to assess whether 1) system reliability was a factor in driving up the prices of electric power and natural gas, and 2) whether the event jeopardized the reliability of the BPS.

An advisory group made up of WECC staff and members of WECC's Operating Committee and Market Interface Committee assessed the event. The group issued a data request to the industry to collect data elements, including actual transfers on major transmission paths into the PNW and Canada, BA Contingency Reserves, and BA loads and available generation. Members of the advisory group also met with several representatives of natural gas pipelines to gather information on pipeline conditions during the pricing event.

This document gives a high-level summary of the event and the advisory group's observations, conclusions, and recommendations.

Conditions Before and During the Pricing Event

Before and during the pricing event, several elements on both the natural gas and electric power systems were operating at lower-than-optimal, but not unreliable, levels. This, combined with weather conditions, created a situation in which natural gas and electricity prices spiked above normal levels in the PNW. Individually, the following factors, which are discussed in detail in this section, may have had a limited impact on pricing. Together, these conditions greatly affected both natural gas and electric prices in the PNW.

1. Weather Conditions: Extended below-average temperatures in western Canada and areas of the PNW created prolonged high heating demand on both the gas system and BPS.
2. Generation Availability: Generation, while adequate, was scarce because—
    a. PNW BA resources were serving native loads, limiting available surplus energy;
    b. Low hydro levels in British Columbia (BC) affected both BC and the PNW;

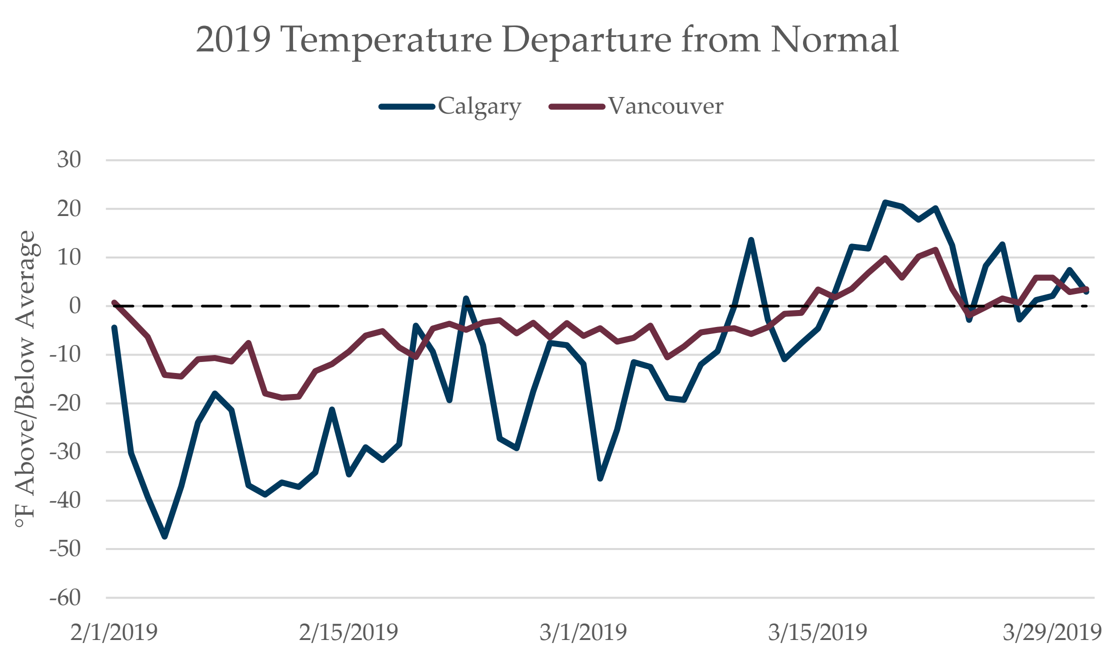
   c. Extended cold temperatures led to extremely low energy produced by wind resources in the PNW;
   d. Gas line capacity was reduced in the Westcoast Pipeline, which was running at 80 percent capacity;
   e. Gas storage was low due to extended withdrawals; and
   f. Forced outage of the Centralia generating unit (600 MW) further reduced the amount of available generation capacity.

3. Transmission Availability: Transmission limitations reduced the ability to import power from elsewhere in the Interconnection. Transfer capability was "zero" south to north on the Pacific DC Intertie (PDCI) due to planned and approved work in Los Angeles Department of Water and Power's (LADWP) system.

1. Weather Conditions

Beginning in late February and continuing into the first four days of March, the PNW and western Canada experienced extended low temperatures. The high temperatures in Vancouver, British Columbia, averaged 4 degrees Fahrenheit below average for the entire month of February, and the average high for Calgary, Alberta, averaged 25 degrees below average during the same period. (Figure 1).

Figure 1



The constant low temperatures stressed natural gas supply, which was already running low after the rupture of the Westcoast Pipeline near Prince George, BC, in October 2018. The rupture reduced the capacity of the Westcoast system by about 20 percent, often more during maintenance work. In addition, the main natural gas storage facility for the PNW—Jackson Prairie—was operating at low pressures[1] due to extensive withdrawals over the winter season. The high demand placed on natural gas by residential heating needs further strained both the gas supply system and gas-fired electric generation.

2. Generation Availability

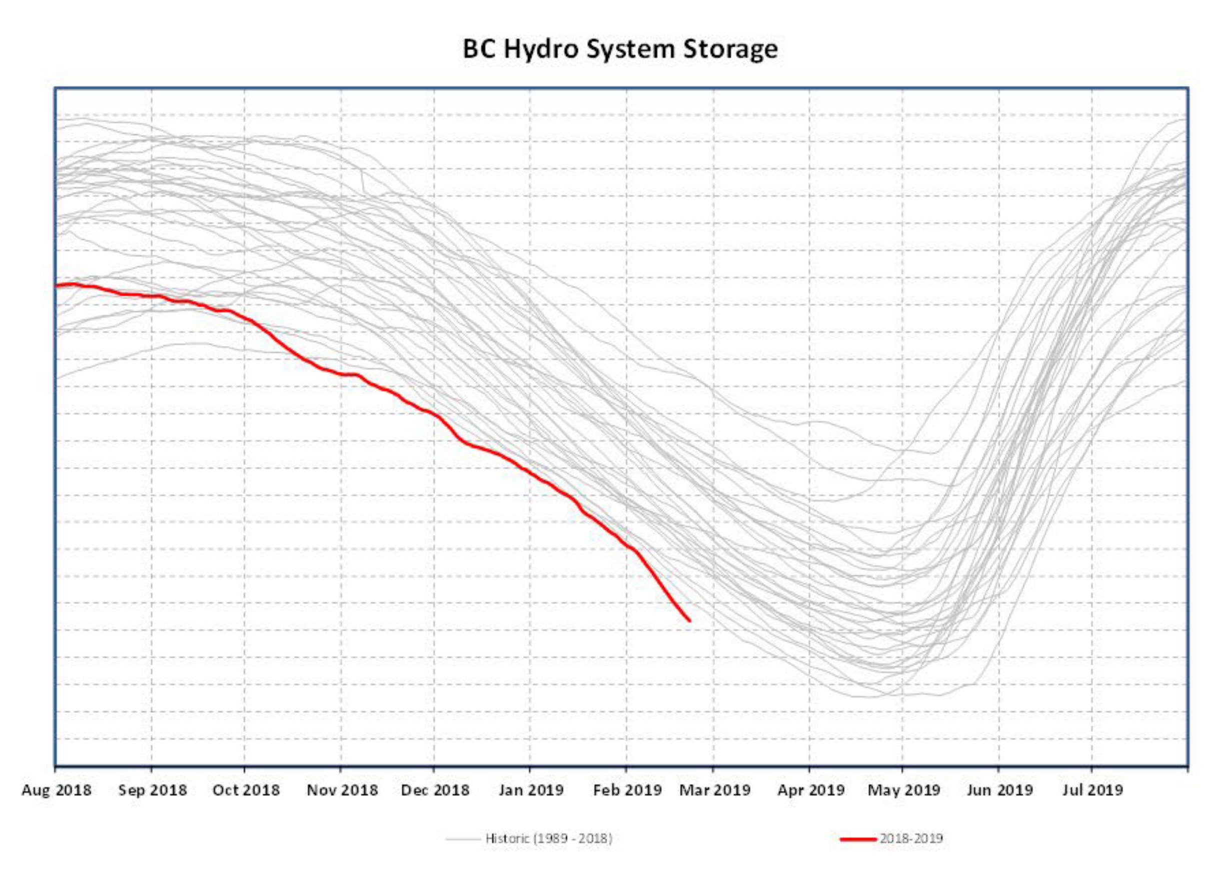
Hydro Conditions

Although the 2018 winter season was a record-setting water year for many areas in the West, the PNW experienced less-than-normal precipitation, which reduced the availability of fuel for electricity generation. Bonneville Power Administration (BPA) reported that, because of the dry conditions across the Basin, Grand Coulee Dam operated through February at minimum discharge rates (except for passing non-treaty, Short-Term Libby Agreement water released from the Canadian projects) to support the fish operations below Bonneville Dam. Despite operating at minimum discharge levels, Grand Coulee ended below the minimum elevation requirement for the February Variable Draft Limit (VDL) and was forecast to come in below both the anticipated March VDL and the April 10 elevation. This caused Grand Coulee to continue operating to minimum discharges to support fish spawning and incubation below Bonneville Dam. Headwater storage projects were all below current flood control guidance and, therefore, also running to minimum discharge levels.

Hydro supply in BC was also reduced during this period. The combined storage of the Williston and Kinbasket reservoirs, which serve as BC Hydro's primary hydro system storage facilities, reached a record seasonal low. BC Hydro saw a need to ensure another reliable supply of energy to meet domestic load over the winter and spring. In late 2018, BC Hydro arranged with Powerex to import energy through the winter at specific levels set by BC Hydro. The Powerex imports were expected to rely primarily on deliveries of Canadian Entitlement energy under the Columbia River Treaty, but also on bilateral procurement from wholesale markets in the U.S. A report on BC Hydro's efforts is attached as Appendix 2.

[1] Pressure in the storage fields facilitates natural gas withdrawals. More gas in storage helps to keep the pressure higher, which allows for more and faster withdrawals for the storage fields.

Figure 2

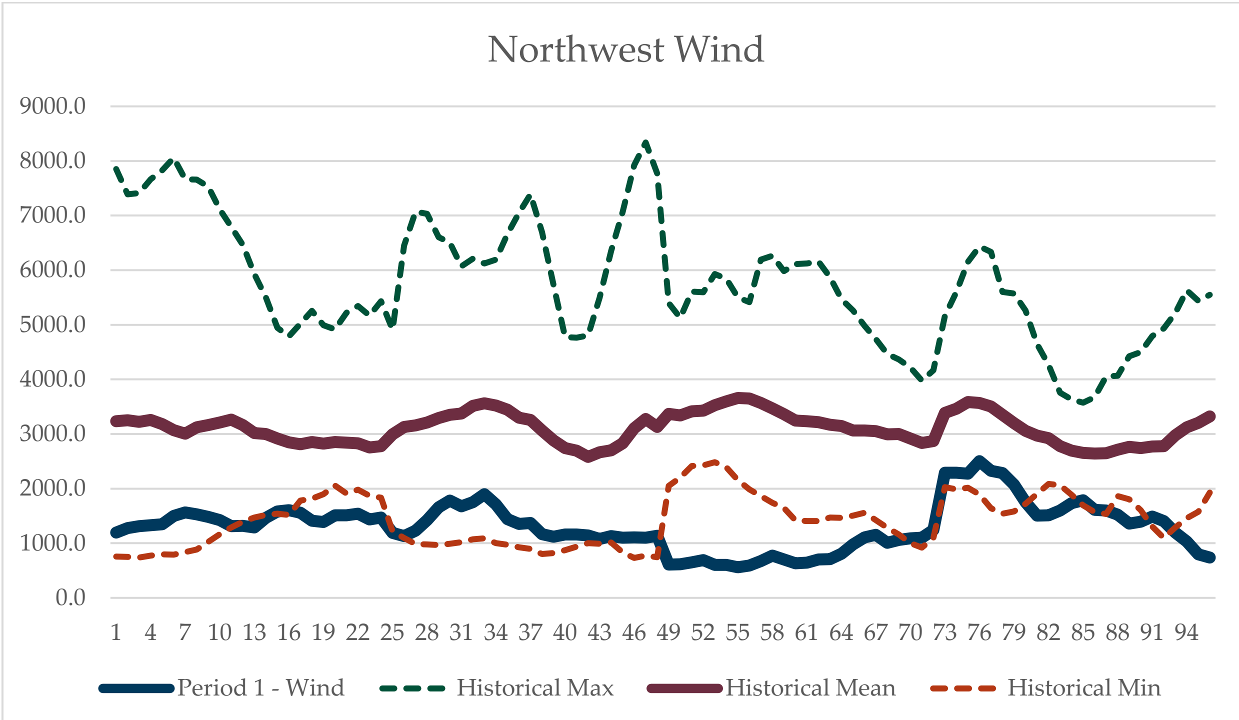


As the power supply became tighter, BPA asked BC Hydro to release more water to increase generation downstream. BC Hydro responded to the request, even though it was experiencing some of the lowest hydro conditions in 15 years.

Wind Conditions

During the price increase, power from wind generation was very low, with an average capacity factor of 11 percent for all wind resources in the Northwest Power Pool. During the same weeks in 2018 and 2017, the average capacity factors were 25 percent and 41 percent, respectively.

Figure 3

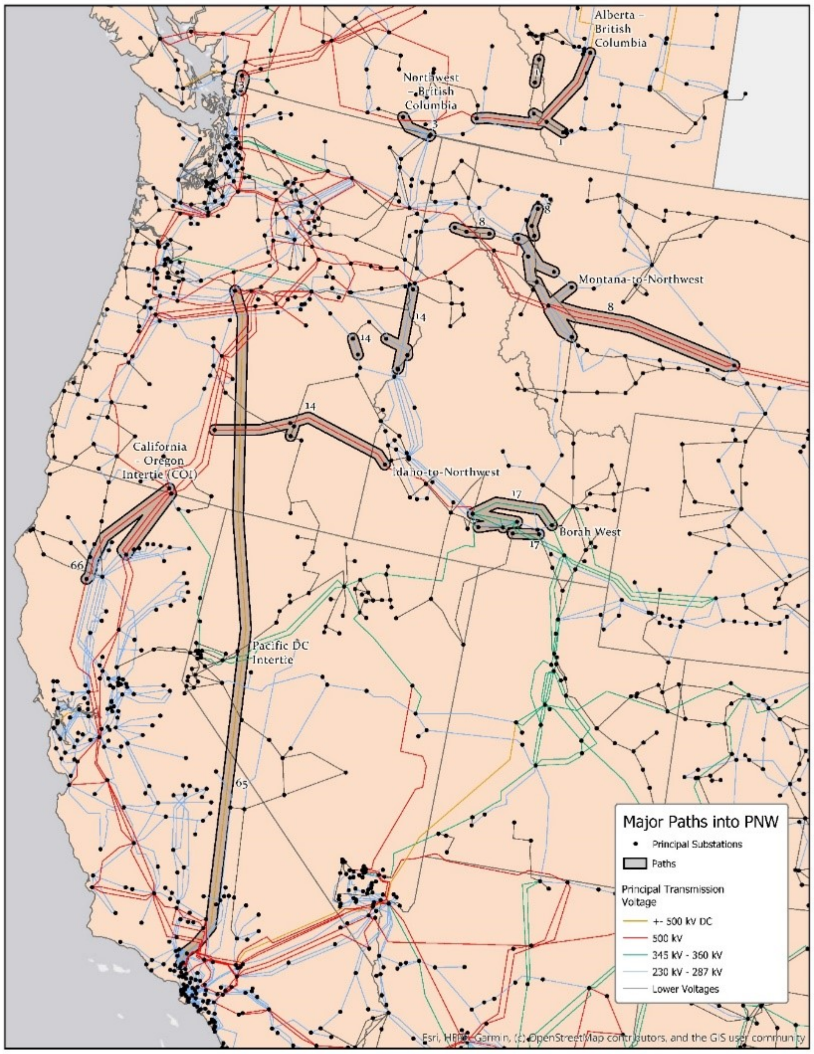


Natural Gas Conditions

Members of the advisory group met with Kern River Pipeline and Northwest Pipeline to discuss several gas topics, including the pricing event. Kern River reported it saw few issues during the period, though that pipe is not directly affected by PNW conditions. Northwest Pipeline did see system limitations and constraints that impacted deliverability (e.g., low inventory at Jackson Prairie, a pipeline operating at reduced pressure), but stated it did not see this as a reliability event. Northwest Pipeline indicated it saw high prices during that period and used strict balancing rules and made phone calls to customers to ensure gas continued to flow and that customers were not leaning on the system.

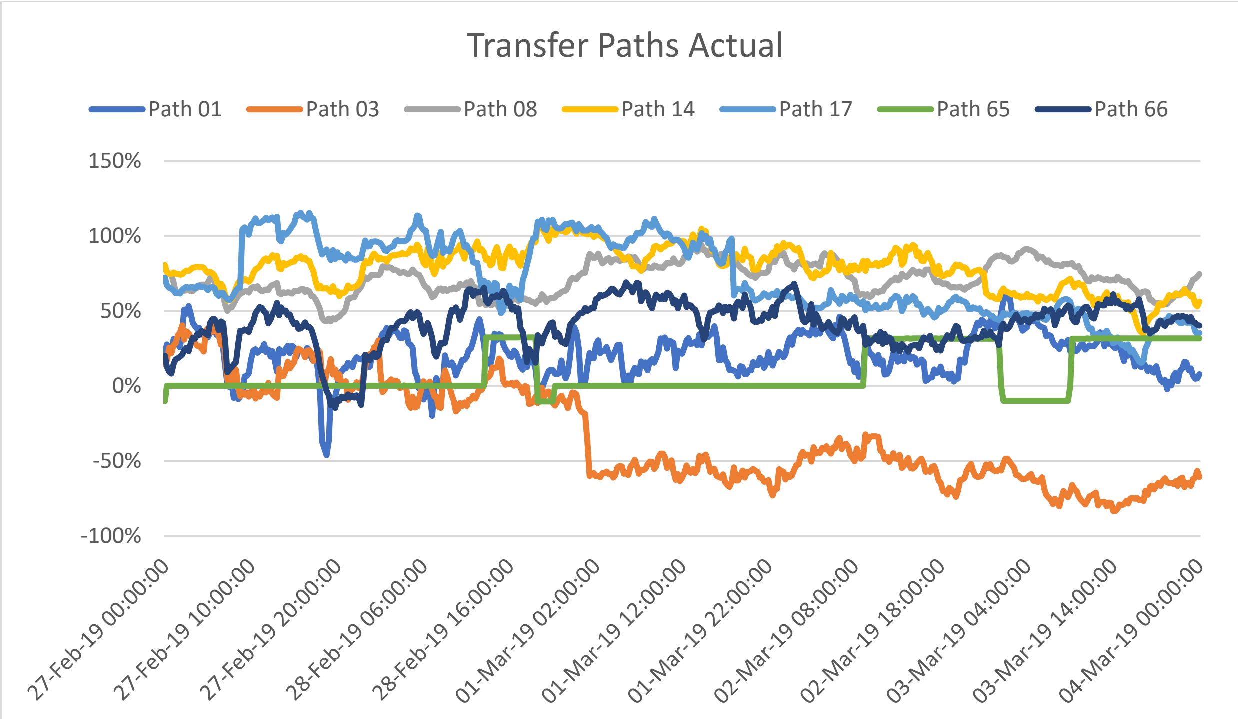
The WECC data request asked the BAs in the PNW if gas-fired generation was impacted during the event. The responses showed that the location of gas generation was critical to possible disruptions to the natural gas supply. Generation on the west side of the Cascade Mountains was affected, while generation on the east side was not.

3. Transmission Availability



Beginning on February 23, the PDCI was de-rated to zero transfer capability south to north due to scheduled and approved transformer maintenance by the LADWP. Historically, power has flowed from the PNW to southern California in the spring, so LADWP scheduled maintenance during the shoulder month. Before the transformer work, the PDCI was rated at 975 MW south to north and would have relieved some of the pricing pressure during this period. As shown in the plots below, transfers were flowing east to west into the PNW on key transfer paths for the early part of the four-day period and then began to back off. This indicates that exports were reduced, and resources were being used to serve native load. Path 3, the path from the PNW to Canada, changed directions during this event, with energy flowing into BC Hydro from the PNW.

Figure 4



[2]

Contingency Reserves

Based on review of the information collected, there was no indication that, during the event, the PNW BAs and the Northwest Reserve Sharing Group had less than the required reserves. Because there were enough reserves available during the pricing event, there were no Energy Emergency Alerts (EEA) and there was no need to shed load to keep the system balanced and stable.

---

[2] Path 1—AB to BC;

Path 3—PNW to BC;

Path 8—MT to PNW;

Path 14—ID to PNW;

Path 17—Borah West;

Path 65—Pacific DC Intertie (PDCI);

Path 66—COI

Observations

Natural Gas Pricing System

During this event, the natural gas pricing system worked as designed—i.e., the pricing increase was not a pricing system malfunction. When residential heating demand increases, it requires more natural gas. When demand for gas increases to the point at which supply cannot cover the demands of residential heating and power generation, gas prices increase. This should encourage a reduction in power generation, allowing gas to supply residential demand. This is what happened during the pricing event.

Generation Mix Diversity

In instances when natural gas prices increase to encourage reduction in natural gas-fueled power generation, power producers should use other resources to cover the difference. When the generation mix is diverse, there is some variety in the type and availability of alternate generation. This was not the case during the pricing event. Hydro, wind, and natural gas resources were limited, forcing the PNW to rely more heavily on coal and nuclear resources.

The ability to support generation during times of low diversity in the generation mix will be more difficult as thermal resources are retired. Several states within the Western Interconnection have established carbon-free mandates (Table 1). In response, electric utilities are retiring most, if not all, of their coal-fired resources and many natural gas-fired resources. (see Appendix 1 for a list of planned major generation retirements from 2019 to 2028). With the retirement of these large, high capacity-factor units, replacement energy will likely come from variable energy sources, mostly wind and solar generation, which have significantly lower capacity factors.

Table 1—State Renewable and Clean Energy Standards

State	Renewable or Clean Energy Standard	Target	Year	
Arizona	Renewable Portfolio Standard	15%	2025	
California	Renewable Portfolio Standard Clean Energy Standard	60% 100%	2030 2045	
Colorado	Renewable Portfolio Standard Clean Energy Goal	30% 100%	2020 2045	
Idaho	No state standard Idaho Power Clean Energy Goal	 100%	 2045	

Montana	Renewable Portfolio Standard	15%	2015	
Nevada	Renewable Portfolio Standard Clean Energy Goal	50% 100%	2030 2050	
New Mexico	Renewable Portfolio Standard Clean Energy Standard	80% 100%	2040 2045	
Oregon	Renewable Portfolio Standard	50%	2040	
Utah	Renewable Portfolio Goal	20%	2025	
Washington	Renewable Portfolio Standard Clean Energy Goal	15% 100%	2020 2045	
Wyoming	None			

Contingency Reserves

While the calculation and reporting of reserves by BAs to the RC was not a contributing factor in the pricing event (no EEAs were issued), the assessment indicates that, under different circumstances, they could be. Reserves are calculated based on unit capacity and do not necessarily consider fuel availability. Limits on the hydro system and wind availability—which were both present during the pricing event—could reduce actual reserve levels below the calculated and reported levels. Fuel-limited resources may be overcounted toward reserves as the full capacity of the unit may be counted without regard to the availability of fuel.

Pricing Event Timing

The timing of the price event may also have been a contributing factor. Natural gas is traded and nominated on Friday for the upcoming Saturday, Sunday, and Monday; while electric power is traded and scheduled on Friday for the upcoming Sunday and Monday. The weather forecast showed cold temperatures over the weekend, which supported natural gas and electric power prices. However, temperatures moderated over the weekend and, by Monday, spot prices for electric power were trading at a range of $40–$200, approaching normal spring and early summer prices.

Conclusions

The pricing event was the result of a combination of many factors, which, taken individually, would not have the same impact on pricing. The increase in natural gas prices during the event directly affected the cost of electric power but did not adversely affect BPS reliability. LSEs and BAs reported no load interruptions, and Peak Reliability declared no EEAs, indicating there were enough electric operating reserves during the event.

Finally, and perhaps most importantly, the generation diversity played a critical role in maintaining reliability during the pricing event. In this case, the resource diversity helped maintain reliability because dispatchable thermal resources were available to make up for resources with fuel limitations. As the generation resource mix continues to change in response to carbon reduction requirements, this type of event may become more common, and may negatively affect reliability. System planning practices need to account for the capacity contribution of the replacement resources during times when the system is stressed, and weather dependent resources may be limited.

Recommendations

The assessment of the pricing event gave insights into both short-term natural gas pricing issues and potential long-term reliability concerns. The advisory group makes the following observations and recommendations to address the issues highlighted in the March 1–4 pricing event.

Observation—Extreme weather events, like the extended cold temperatures experienced in western Canada, are happening more often and may be the "new normal."

Recommendation 1—As states continue to apply requirements for low- or zero-carbon power generation, LSEs and BAs need to plan for extreme and extended weather scenarios to ensure generation and transmission resources are available to serve demand under all conditions.

Observation—The March pricing event also showed that, under the "new normal" weather future, the scheduling of planned maintenance may need to be re-examined. Historically, extended generation and transmission maintenance outages have been scheduled for the shoulder months—March through May and September and October—to ensure these resources are available for peak summer and winter demand.

Recommendation 2—Transmission and generation owners and operators and BAs should reevaluate their maintenance practices in coordination with RCs to make sure enough resources are available to cover demand under all conditions.

Observation—The examination highlighted the importance of understanding how BAs report contingency reserves to the RCs.

Recommendation 3—Industry should standardize the way fuel-limited resources are reported for contingency reserves to ensure BAs and RCs know to what degree and for how long the reserves can cover demand.

Observation—The transaction from high capacity-factor thermal generations to low capacity-factor variable generation resources is changing how entities plan and operate the BPS.

Recommendation 4—WECC, LSEs, and BAs must perform analyses to determine the capability of the Western Interconnection to meet demand under extreme weather conditions. WECC, LSEs, and BAs must perform various studies, including Power Flow, Generation Resource Adequacy, and Transmission Resource Adequacy. These studies should focus on the anticipated increase in low capacity-factor wind and solar resources that are expected to replace high capacity-factor generation fired by coal and natural gas.

These studies must look at all resources in the Western Interconnection, as LSEs may be counting the same resources and only an interconnection-wide look will show the generation and transmission adequacy of the electric grid.

Appendix 1: Planned Major Generation Retirements

Name	Fuel	Size (MW)	Location	Retirement Date
Ocotillo	NG	220	AZ	7/1/2019
H Wilson Sundt 1,2	NG	162	AZ	8/31/2019
Battle River 3	Coal	148	AB	12/1/2019
Navajo 1-3	Coal	2310	AZ	12/22/2019
Inland Empire	NG	750	CA	12/31/2019
Colstrip 1,2	Coal	600	MT	12/31/2019
2019 Retirements		**4190**		
Alamitos 1-6	NG	2010	CA	12/31/2020
Boardman	Coal	550	OR	12/31/2020
Centralia 1	Coal	670	WA	12/31/2020
Huntington Beach 1,2 (Potential Delay)	NG	450	CA	12/31/2020
Ormond Beach	NG	1491	CA	12/31/2020
Nucla	Coal	100	CO	12/31/2020
Redondo Beach (Potential Delay)	NG	1310	CA	12/31/2020
2020 Retirements		**6581**		
Fort Churchill 2	NG	113	NV	12/31/2021
North Valmy 1	Coal	254	NV	12/31/2021
2021 Retirements		**367**		
Oakland	NG	165	CA	10/1/2022
Comanche 1	Coal	330	CO	10/31/2022
San Juan 1,4 (Potential Retirement)	Coal	847	NM	12/31/2022
Naughton 1,2 (Potential Retirement)	Coal	357	WY	2022
Jim Bridger 1,2 (Potential Retirement)	Coal	1063	WY	2022
2022 Retirements		**2762**		
Diablo Canyon 1	Uranium	1080	CA	11/30/2024
Centralia 2	Coal	670	WA	12/31/2024
Cholla 4	Coal	387	AZ	12/31/2024
Newman 1-3	NG	247	TX	12/31/2024
Scattergood 1,2	NG	326	CA	12/31/2024
2024 Retirements		**2710**		

Name	Fuel	Size (MW)	Location	Retirement Date
Comanche 2	Coal	330	CO	10/31/2025
Diablo Canyon 2	Uranium	1080	CA	11/30/2025
Battle River 4	Coal	148	AB	12/31/2025
Craig 1	Coal	427	CO	12/31/2025
Fort Churchill 1	NG	113	NV	12/31/2025
Harry Allen 1	NG	76	NV	12/31/2025
Intermountain GS 1,2	Coal	1800	UT	12/31/2025
North Valmy 2	Coal	268	NV	12/31/2025
2025 Retirements		**4242**		
Battle River 5	Coal	148	AB	12/1/2027
Dave Johnston 1-4	Coal	762	WY	12/31/2027
2027 Retirements		**910**		
Harmac Biomass	BIO	55	BC	8/12/2028
Sheerness 1,2	Coal	816	AB	12/31/2028
2028 Retirements		**871**		
Total Retirements		**22633**		

Appendix 2: BC Hydro Winter 2019 Preliminary Report

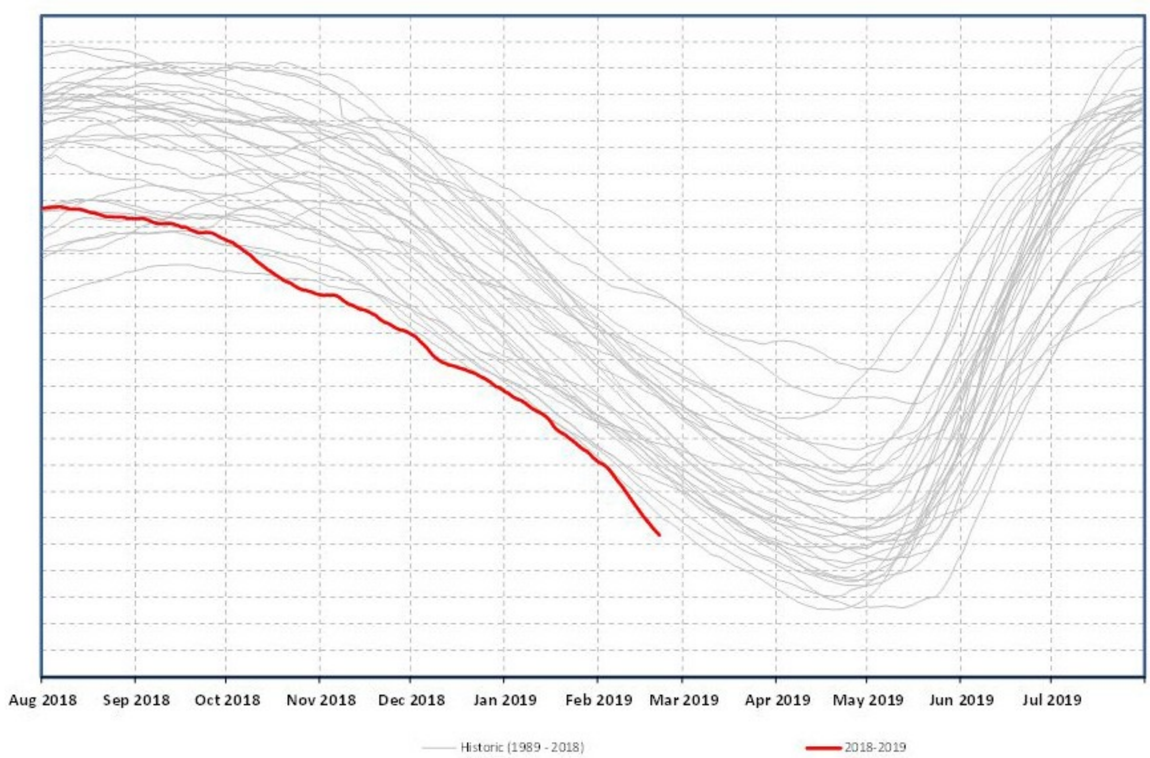
Challenging system conditions in British Columbia have resulted in BC Hydro's need to procure a substantial volume of energy across the Winter 2019 Period to serve domestic load. This preliminary report seeks to provide a high-level overview of those conditions and BC Hydro's response to manage its reservoir operations and ensure adequate supply over the winter season.

I. BC HYDRO SYSTEM CONDITIONS AND RESPONSE: EARLY WINTER 2019

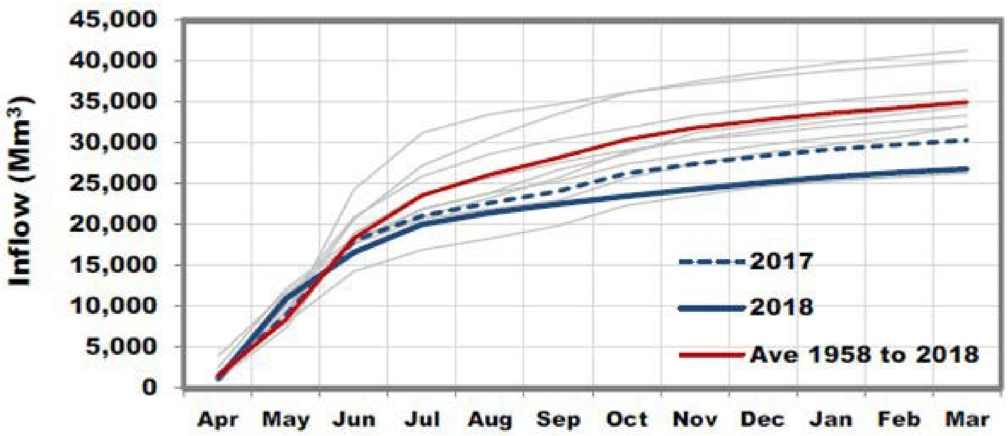
At the start of the winter 2019 season, BC Hydro identified a potential substantial net short energy position through April 2019, when spring freshet could be expected to yield substantial inflows. In particular, BC Hydro's October energy studies indicated a potential 1,700 GWh energy deficit for the period ending March 31, 2019 and an additional potential 1,000 GWh energy deficit for April 2019. These projected deficits were based on a number of factors, including low inflows into BC Hydro's primary storage reservoirs in September and October, a projected increase in demand for electricity as a result of the Enbridge Pipeline Explosion, and an increase in BC Hydro's winter load forecast.

A. Early Indicator: BC HYDRO SYSTEM STORAGE DEFICIT

In October 2018, the combined storage of the Williston and Kinbasket reservoirs, which serve as BC Hydro's primary hydro system storage facilities, reached a record seasonal low, as shown in the graph below.



Dry conditions in the Williston basin alone resulted in four successive months of low inflows, with September, October, and November inflows being the 3rd, 2nd, and 4th lowest inflows observed since 1958. By October, storage levels at Williston were seven feet below the historic 10-year average elevation. The chart below provides an illustration of historical cumulative inflows to the Williston reservoir. The blue line is the Williston reservoir cumulative inflows to the end of February 2019 and forecast to the end of March 2019.



B. Early Indicator: GAS SUPPLY DISRUPTION

In addition to the low inflows to BC Hydro's reservoirs and restrictions on operations, the October 2018 Enbridge Pipeline Explosion substantially reduced natural gas supply to southern BC and the Pacific Northwest (Vancouver, Seattle, Portland). Heading into the winter, BC Hydro expected that the reduction of this regional natural gas capacity could create natural gas curtailments across the winter, with capacity potentially 20% less than normal winter operating capacity along with instances of more significant restrictions. In general, constraints arising from the Pipeline Explosion resulted in an increased demand for electricity in the market to replace gas-generating units that would have otherwise run. For example, such constraints caused BC Hydro to remove the gas-fired Island Generation plant from the supply stack in October 2018, further reducing BC Hydro supply.

C. BC Hydro Early Winter Response

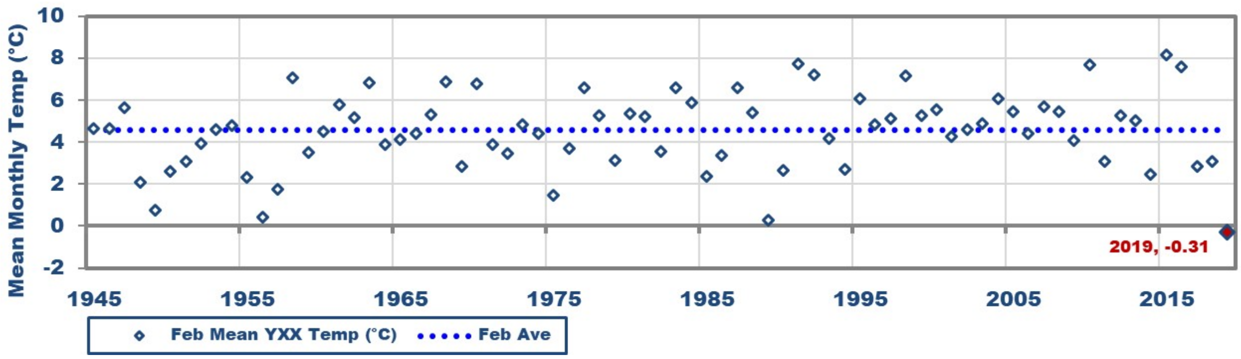
To address the forecast shortfall, BC Hydro anticipated a need to take steps to ensure an additional reliable supply of energy to meet domestic load over the winter and spring period. In late 2018, BC Hydro made arrangements with Powerex to import energy across the winter period at specified target levels that would be set, and could be adjusted by, BC Hydro. Powerex imports were expected to rely primarily on deliveries of Canadian Entitlement energy under the Columbia River Treaty but also on bilateral procurement from wholesale markets in the US.

II. LATE WINTER – BC HYDRO SYSTEM CONDITIONS AND RESPONSE

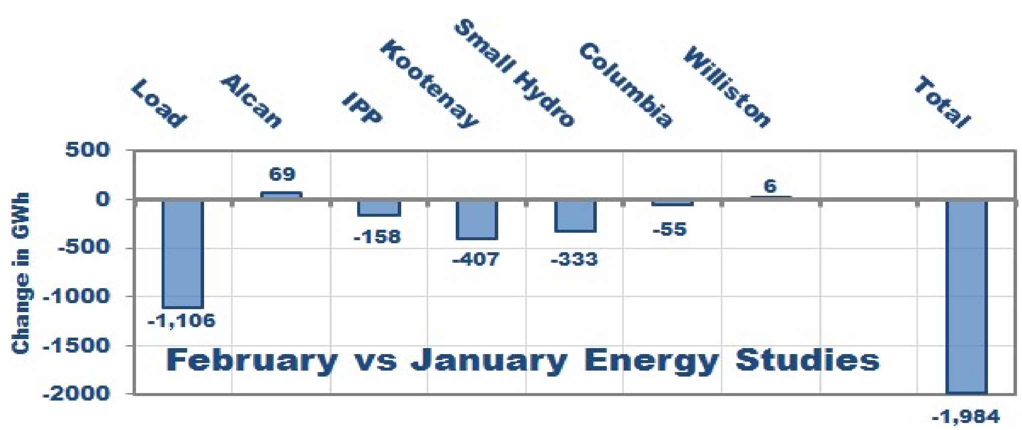
In early winter, the volume of energy BC Hydro needed was large, yet uncertain. But moving deeper into the winter season, the volume BC Hydro needed to close the gap grew, in great part as a result of continued cold weather and high demand, particularly throughout February and into early March.

A. Late Winter System Conditions

Entering into February, system conditions in BC worsened beyond initial predictions. February 2019 was the only February on record with an average temperature below freezing; the chart below shows February 2019 to be the coldest Lower Mainland temperatures observed since 1945.



With this updated information, BC Hydro's February 2019 energy studies documented an increase in expected load and a significant decrease in expected available energy over its January forecast, driven primarily by the cold snap across February, as well as reductions in small hydro and IPP output in the province, as expected to be associated with the severe cold snap. In particular, as the chart below shows, BC Hydro's February 2019 study reflected an expectation of a nearly 2,000 GWH increase in overall system shortfall, and cold conditions were forecast to persist into March.



By the end of February, BC Hydro had recorded its highest-ever monthly load, its highest daily average energy consumption, and its highest recorded peak hourly demand for the month of February.

B. BC Hydro Late Winter Response

1. Additional Procurement to Address Shortfall

In late February, BC Hydro requested Powerex to engage in additional targeted imports on a sustained basis at a level approaching import limits across the BC-US border for the March and April period, in order to ensure that BC's reservoirs were maintained at or above minimum operating levels. In response, Powerex took steps to satisfy BC Hydro targets using Canadian Entitlement energy under the Columbia River Treaty, along with energy procured from wholesale markets in the US and Alberta.

2. Coordination with Bonneville Power Administration

BC Hydro staff received a request from Bonneville Power Administration in late February / early March period, which it agreed to, for the release of a specified volume of non-treaty water from BC Hydro's Arrow Lakes facility to enable additional generation of electricity on Bonneville's downstream facilities.

3. Public Communication

BC Hydro posted a press release on March 1, 2019, informing the public about challenging system conditions in BC that required BC Hydro to secure a substantial volume of import supply over the winter months, and urging BC Hydro customers to engage in demand reduction measures wherever possible.

See: https://www.bchydro.com/news/press_centre/news_releases/2019/february-power-load.html

Appendix 3: Volunteers for Pricing Event Advisory Group

Industry Volunteers

Robert Romine .... LS Power Development, LLC

Andy Meyers .... Bonneville Power Administration

Kevin Cardoza .... Eugene Water & Electric Board

Greg Park .... Northwest Power Pool Corporation

Sueyen McMahon .... Los Angeles Department of Water and Power

Scott Winner .... Bonneville Power Administration

Bill Casey .... Portland General Electric Company

JJ Jamieson .... Perennial

Mike Evans .... Shell Energy North America (US), L.P.

Marilyn Franz .... NV Energy

Bud Freeman .... Seattle City Light

Aliza Seelig .... Seattle City Light

Eric Baran .... Western Interconnection Regional Advisory Body

Raj Hundal .... Powerex, Inc.

Chris Sanford .... Bonneville Power Administration

Wade Kiess .... Peak Reliability

Greg Mendonca .... Pacific Northwest Generating Cooperative

Gary Farmer .... Transmission Agency of Northern California

Paul Wetherbee .... Puget Sound Energy, Inc.

MIC and OC Leadership

Brad Bouillon .... California Independent System Operator

Robert Follini .... Avista Corporation

Rich Hydzik .... Avista Corporation

Bert Peters .... Arizona Public Service Company

WECC Staff

Steve Ashbaker .... WECC

Layne Brown .... WECC