PNUCC

Bringing the *Power* of good ideas *Together.*

December 12, 2018

Mr. Jim Yost, Chair
Northwest Power and Conservation Council
851 S.W. Sixth Avenue, Suite 1100
Portland, Oregon 97204

Dear Chairman Yost,

On behalf of the PNUCC Board of Directors and members we offer the attached comments on your *draft 7th Power Plan Mid-Term Assessment*. These observations and suggestions were developed in collaboration with the PNUCC System Planning Committee, whose membership includes technical staff from various Northwest utilities.

The Council's power planning efforts can have implications for PNUCC member utilities. Thus, our goal continues to be that the Council's work accurately portrays the state of the Pacific Northwest power system and the challenges facing utilities, especially now as they are making the transition to cleaner and more efficient systems.

Nothing we are offering should be a surprise, nor suggest a need for further effort regarding the *7th Power Plan*. In fact, the intention of many of our comments are in the spirit of getting prepared to tackle the development of the *8th Plan*. Please accept them in that spirit.

We've greatly appreciated the ongoing dialogue we've enjoyed with Council staff regarding our comments. And we are looking forward to working with you to build the next plan that will provide a solid backdrop for the innovative efforts of utilities to meet their customers' needs and provide an adequate, efficient and reliable power supply for the region.

Sincerely,

Shauna McReynolds

Shauna McReynolds
PNUCC Executive Director

The transmission and distribution deferral value revamp process has been appreciated

During the development of the 7th *Power Plan,* PNUCC commented that the transmission and distribution (T&D) deferral value used by the Council was out-of-date. The T&D deferral value is applied to resources that reduce the need for T&D investments. These resources include demand-side management and certain supply-side resources (in the *7th Plan* gas power plants west of the Cascade Mountains received a transmission deferral credit).

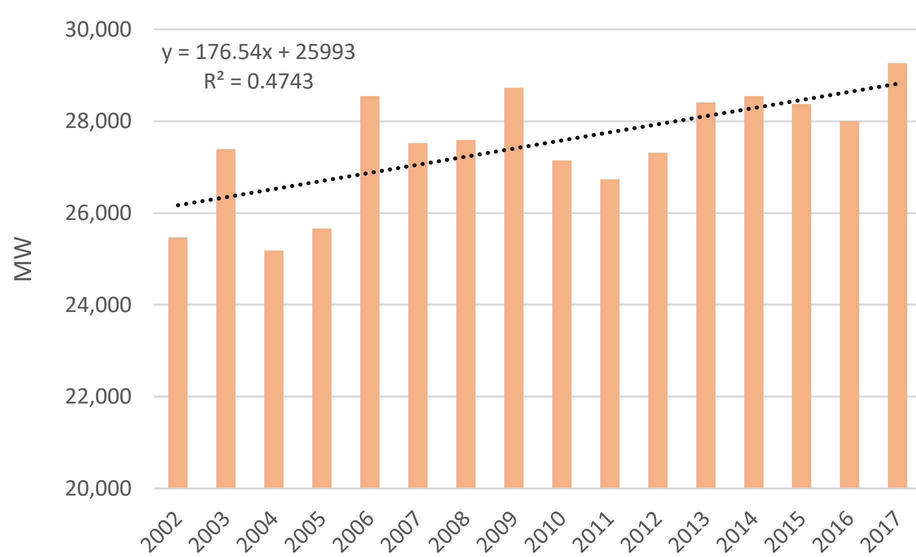
The final *7th Plan*, in part due to PNUCC's comments, recommended investigating a new T&D deferral value methodology. Council staff have done a good job involving utilities in their discussions, have been thoughtful about the process, and are currently collecting data from utilities for the formation of a new value. **PNUCC thanks Council staff for taking leadership on this issue and looks forward to continued engagement as a final value is developed.**

Load forecast adjustment better reflects regional trends

PNUCC favors the upward adjustment to the summer load forecast for the *7th Plan Midterm Assessment*. PNUCC has been concerned for a number of years that the summer load forecast used by the Council is too low. This concern is based on the *PNUCC Northwest Regional Forecast* load data, discussions with utility load forecasters, and historical Northwest loads as reported by the Power Council (see Figure 1). PNUCC's past comments on the Council's load forecast have come via the Resource Adequacy Advisory Committee (RAAC), including requesting a sensitivity with higher summer loads and lower winter loads as part of the 2018 Adequacy Assessment. **We expect that the 2019 Adequacy Assessment will include higher summer loads as well.**

Lastly, for the final Midterm Assessment, it would be helpful to provide the load forecasts after expected energy efficiency (the only forecast in the draft *Assessment* is prior to energy efficiency).

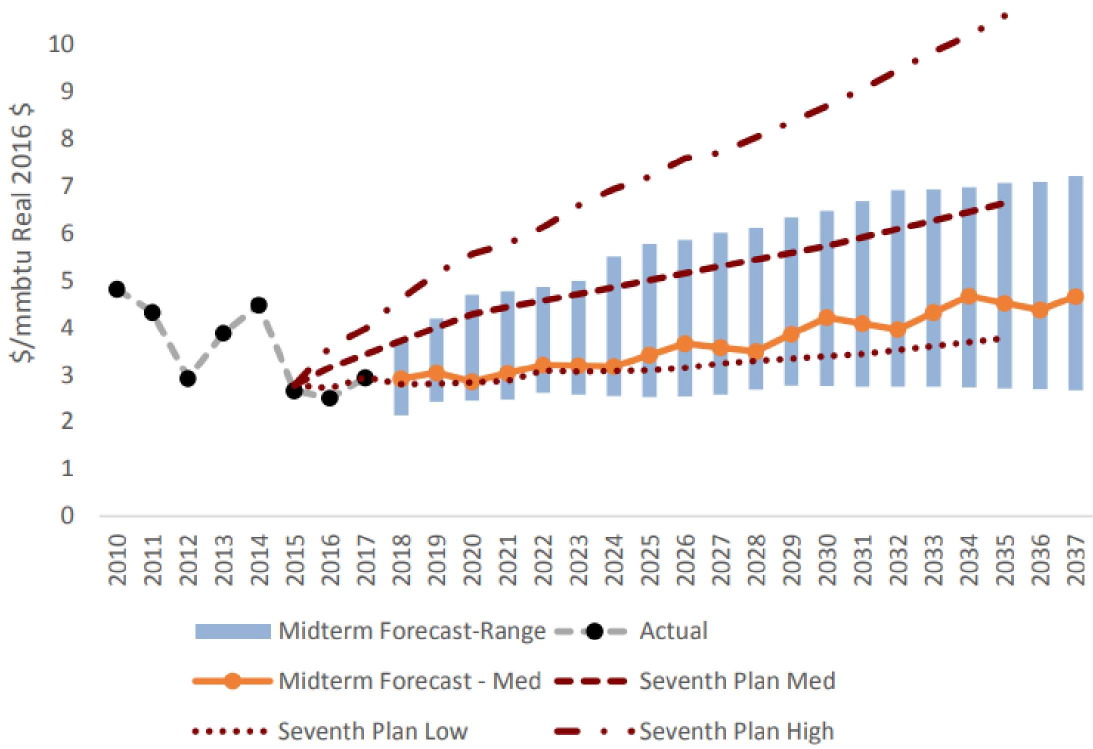
Figure 1 – Northwest summer peaks are trending upwards



Natural gas price forecast better fits current trends

PNUCC supports the downward adjustment to the Council's natural gas price forecast. One common narrative over the past few years has been the continuation of inexpensive natural gas. There are robust supplies in Canada and the US Rockies, the basins that feed the Northwest. This glut of supply has placed downward pressure on prices. **It is good to see the Council downwardly adjusting their gas price forecast to reflect this continued reality.**

Figure 2 - 7th Plan Natural Gas Forecast (source: draft Midterm Assessment)



There are events that can affect gas supply and prices temporarily or unexpectedly. These are likely accounted for within the *7th Plan* via RPM's stochastics (the range of prices the RPM uses is different and wider than the input range). **It could be insightful for the Midterm Assessment to show the full range of prices used by the RPM.**

Supply-side resource costs in the ballpark of utility IRP estimates

PNUCC finds the supply side resource cost changes in the Midterm Assessment to be in-line with industry expectations. Since the *7th Plan*, there have been changes to resources capital costs, most notably to solar, wind, and frame gas units. **Council staff have done a good job capturing these changes in the *Midterm Assessment* draft and explaining these changes over a series of Generating Resource Advisory Committee meetings.**

Table 1 – 7th Plan Midterm Assessment Supply Side Resource Capital Costs

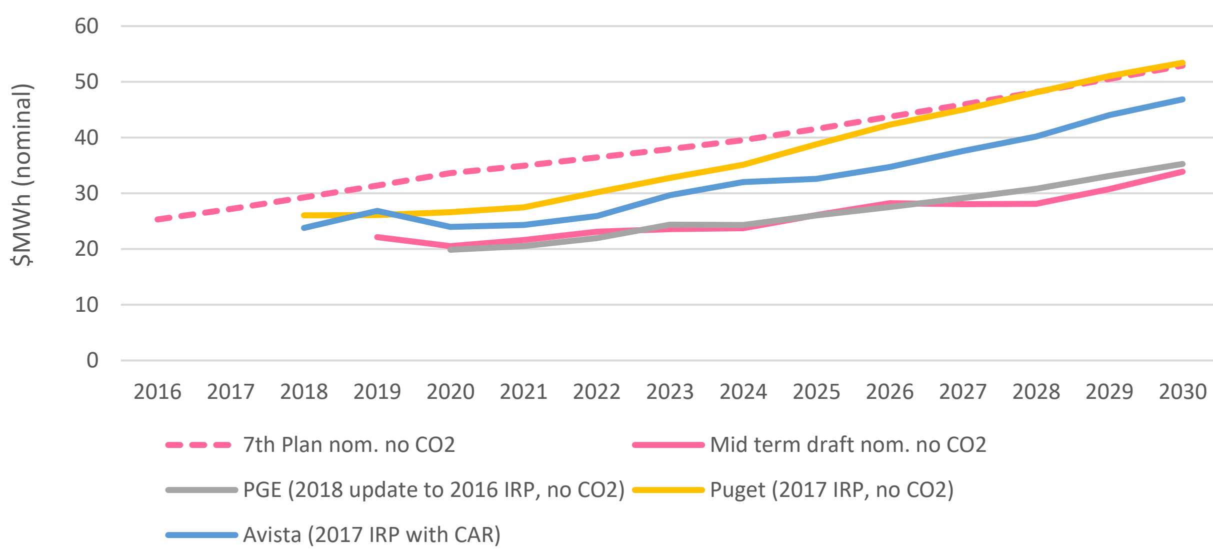
	7th Plan (*$/kw*)	**Updated (*$/kw*)**
CCCT wet	$1,220	$1,100 - $1,300
CCCT dry	$1,369	$1,200 - $1,400
Frame	$859	$500 - $ 650
Reciprocating	$1,382	$1,250 - $1,450
Wind (Gorge)	$2,240	$1,500 - $1,700
Wind (MT)	$2,240	$1,500 - $1,700
Solar	$2,238	$1,350 - $1,500

PNUCC is curious why demand-side resource prices were not updated. In the *7th Plan*, especially within first few years, few supply-side resources are acquired, but many demand-side resources are acquired and recommended to the region. It is a missed opportunity to not update the cost of demand-side resources.

Power price forecast in the ballpark with utility IRPs

The power price forecast from the *7th Power Plan* to the draft *Midterm Assessment* fell significantly. This is likely due to the drop in the gas price forecast. The Midterm forecast sits at the low end of utility price forecasts, but still within that range. Although PNUCC finds the forecast to be in the ballpark, **PNUCC recommends changing the draft *Midterm Assessment* language to reflect the magnitude of the drop**. The document currently reads "…the prices trend slightly lower on average…" as compared to the *7th Plan*, which is an understatement given that the prices are 30% to 40% lower.[1]

Figure 3- Midterm Assessment Power Prices lower, still in the ballpark



PNUCC has some observations on monthly price differentials and hourly price shapes. In the *7th Plan Midterm Assessment* winter power prices trade at a premium to summer power prices. This differs from the trend seen in recent years. Additionally, in the later years of the forecast power prices start to flatten out on the hourly level, which is counter to current trends (prices today, at least in CAISO where hourly data are easily accessible, have more hourly variation than a few years ago, largely due to solar development). **PNUCC recommends further investigation of monthly and hourly price differentials going into the *8th Power Plan*.** And similar to the gas price forecast, it could be useful to see the full range of prices RPM uses (i.e. the 800 variations created based on the inputs).

Attachment A explores these seasonal and hourly relationships using the *Midterm Assessment* hourly prices and historical day-ahead-market on-peak prices (as reported by ICE).

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[1] This document is comparing the *7th Plan* input prices to the draft *Midterm Assessment* input prices (both from AURORA). The *7th Plan* RPM output prices, which are not shared in the *Midterm*, are slightly lower than the inputs.

Demand response modeling improving, needs to be incorporated into Council work

The test for adequacy in the Council's RPM was set in the *7th Plan* largely via quarterly capacity margins. These margins came from the Council's adequacy model, GENESYS. GENESYS was also used to check select RPM builds for adequacy. GENESYS is limited in a few areas, including its modeling of demand response. During the *7th Power Plan*, GENESYS understood demand response as a two-dimensional resource, with a set MW capability and a set number of MWh it could use. This misses program attributes, including program duration, program time-of-day usability, usability per week/month/season/year, and other attributes. It also lumps all the programs together, which could create other problems (programs combining their energy and capacity).

Table 2, August period 2 DR example [2]

Hour	Outage before (MW)	Outage after DR/standby (MW)
7	**527**	**0**
8	**566**	**0**
9	**687**	**0**
10	**809**	**0**
11	**606**	**0**
15	122	0
16	328	0
17	329	0
18	328	0
19	328	0
20	328	0
21	333	0
22	336	0

An example of the model not reflecting demand response program attributes is in the table to the right. It shows a day in August where GENESYS fixed an outage using demand response. Without demand response, the hours listed in the table have an outage. After demand response is applied, the outage is solved in every hour. However, the solution was unrealistic since summer demand response programs are typically not available in the morning and/or in late August.[3] In the model output there are numerous examples like this, in both summer and winter seasons, where demand response is unrealistically solving outages (there are also many instances of demand response solving outages in a realistic fashion).

It is clear that Council staff recognize this issue as well. The redeveloped GENESYS model will have more specific demand response inputs, and BPA/Council staff have developed improved demand response inputs for the existing GENESYS model. **PNUCC recommends that future Council adequacy work better incorporate the multifaceted attributes of demand response via newly developed modeling tools.** In addition to considering this in the development of the *8th Power Plan*, PNUCC hopes this is incorporated into the *2019 Resource Adequacy Assessment* of year 2024.

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[2] Model output from GENESYS runs as part of the 2018 adequacy assessment for year 2023

[3] See Idaho Power's 2017 Demand-Side Management Report. For example, the irrigation DR program runs from June 15 to August 15 (p142) and is available from 1:00 PM to 9:00 PM. Flex Peak runs the same dates and from 2:00 PM to 8:00 PM. https://docs.idahopower.com/pdfs/EnergyEfficiency/Reports/2017DSM.pdf

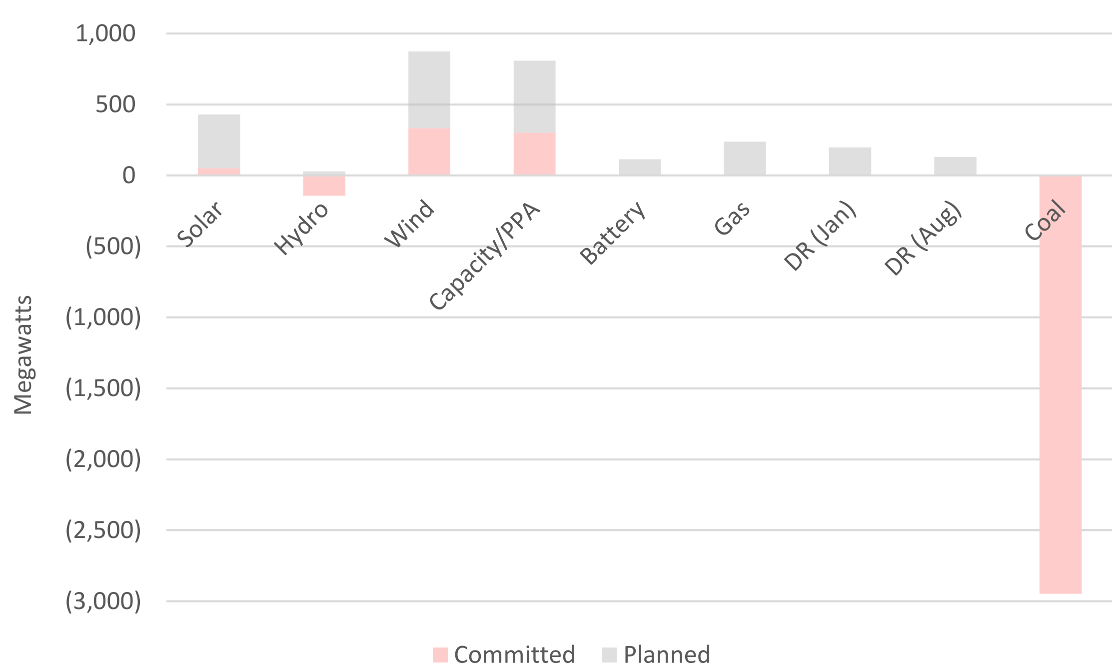
Characterization of future resources looks optimistic

The Council writes on page 2 of the draft *Midterm Assessment* that “The region faces a potential shortfall in resources needed to meet electricity demand after 2020. However, regional utilities have identified sufficient resources in their resource plans to fill the gap.” PNUCC is confident that Northwest utilities are planning to ensure adequacy, but does not see specific solutions as yet identified.

The Council found, in their *2018 Adequacy Assessment* for year 2023, that the region would need over 600 MW of resource similar in characteristic to a natural gas power plant to return the system to a Council defined acceptable adequacy level. Going forward, as more coal units retire, this value could grow.

Looking at committed and planned resources for the Northwest out of the *2018 PNUCC Northwest Regional Forecast*, there are few dispatchable resources slated to come online, as shown below (the gas unit shown is not firm and anticipated to come online in 2025). Many of the capacity/PPA resources listed below could be contracts to existing Northwest resources, and not necessarily new builds. Again, although PNUCC is confident that Northwest utilities are working to ensure system adequacy, the resources needed to maintain adequacy have not been yet identified. **PNUCC recommends that the Council modify the report language to note that the resources needed for adequacy tomorrow have not been expressly identified today.**

Figure 4 – 2018 PNUCC Northwest Regional Forecast Planning & Committed Resources through 2025



Provide context around regional energy efficiency goals

In the draft *7th Power Plan*, the Council explored sensitives regarding the impact of gas prices (and thus wholesale electric power prices) on modeled optimal energy efficiency levels. The takeaway, as shown in Table 3, was that lower gas prices lead to less energy efficiency. Other factors likely impact energy efficiency achievements as well. **PNUCC recommends that the Council discuss key factors that add uncertainty around the magnitude of energy efficiency acquisitions, and if those factors today are different than forecasted in the *7th Power Plan*.**

Table 3 – Draft 7th Plan RPM, Impact of lower gas prices

	2C - Carbon risk	S2.1 - low gas prices & carbon risk
EE by 2021 (aMW)	1,395	1,298

PNUCC, and others, recommended using an energy efficiency range in the *7th Power Plan* (1,300 to 1,450 aMW, rather than the 1,400 aMW target) in part due to forecast uncertainty surrounding gas prices, loads, and other factors. **PNUCC recommends identifying a range for energy efficiency in the *8th Plan*** to better fit the ever-evolving energy landscape.

It would be useful to see how the Council expects the savings to be met. This could be done by breaking out the 1,400 aMW target by utility programs, codes & standards, NEEA, and other. If there are over or under achievements, it would be useful to know what segment is responsible. **PNUCC recommends that the Council identify the bins they expect the 1,400 aMW of energy efficiency to come from.**

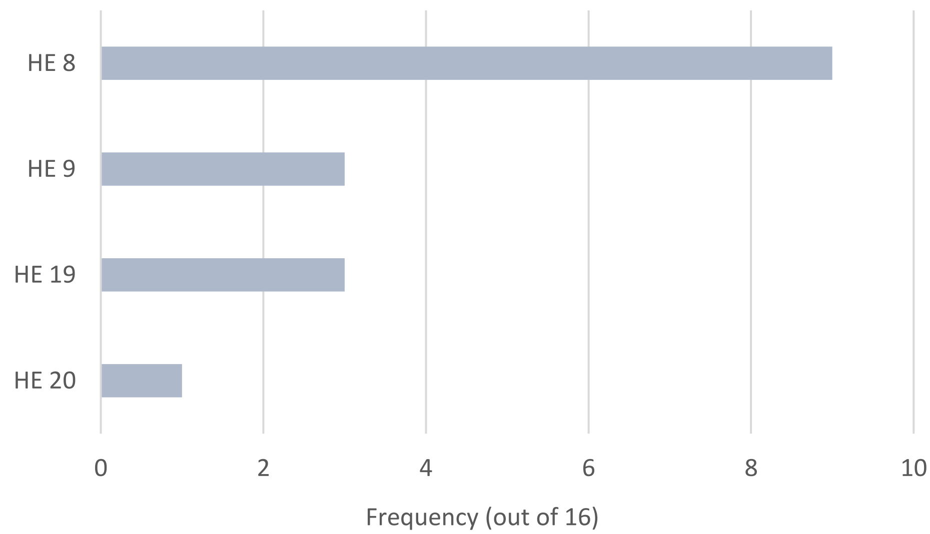
The peak impact of electric vehicles should be better investigated

In the *7th Power Plan*, the Council estimated that in 2025 the Northwest would have 611,000 electric vehicles (medium case). The Plan also estimated that those vehicles would produce 12 MW of peak load. This translates to 0.02 kw of peak load per electric vehicles (kw/EV). Looking at recent literature, this value appears to be low. E3, a consultancy, using EV Project data, found a peak value of 1.3 kw/EV in a recent report. Avista has seen peak kw/EV values at 1.0 kw/EV in their service territory. And a recent CPUC report on EVs in California had a peak value of 0.76 kw/EV during an average day in year 2025. **PNUCC recommends that the Council update their electric vehicles peak impact estimate.**

The peak need hour for power planning should be investigated

The footnote on page 4-3 of the *Midterm Assessment* notes that "the regional winter peak is defined as 6pm on a weekday (in the winter) … (and) summer peak is defined as 6pm on a weekday." Looking at historical regional load data from 2002 to 2017 (provided by the Council to PNUCC) we find that the region's most common, and largest, winter peaks occur in the morning, in hours ending 8 and 9. This is illustrated in Figure 5 below (the largest winter peak in the past decade occurred in hour ending 9).

Figure 5 – Annual Northwest peak hours, 2002 - 2017



In the summer, historically, the peak hour usually occurs in hours ending 16 and 17. However, the hour of highest stress/highest value for a resource (including energy efficiency) may be shifting later in the day in the summer. In California, the highest priced electricity market hours are now hours ending 19 and 20. This is due to relatively high-load levels and decreased solar production due to the setting sun. PNUCC does not have data on hourly Northwest prices, but this trend may be evident in the Northwest as well and could be examined in the winter too.

For future power planning work, PNUCC recommends that the Council adjust the regional peak hour to better align with historical data and explore if the highest load hour or most stressful/high price hour makes more sense for peak needs. This could impact the capacity value that resources provide.

Attachment A – Power price forecast questions

SEASONAL QUESTION

One question PNUCC recommends looking into regarding the power price forecast is the difference between seasonal prices. Recently, as shown in Table 4 below, summer power has traded at a premium to winter. However, the *Midterm Assessment* forecast finds the opposite, with winter prices trading higher than summer.

Table 4 – Average Mid-C Power Prices

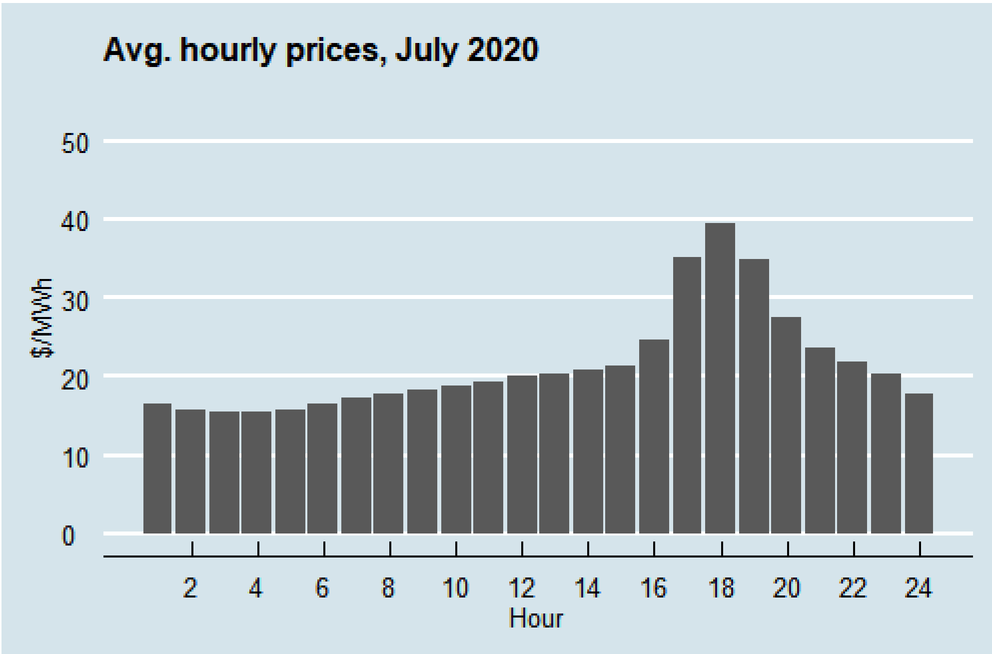
	Average $/MWh	
	Summer	**Winter**
2012-2018 historical (ICE, DAM)	36.94	29.95
2020 Midterm (hourly)	20.74	22.2
2026 Midterm (hourly)	28.59	32.23

It could be helpful to dig into why the *Midterm* is seeing different seasonal trends than the recent historical data. PNUCC staff suspects that gas constraints in Southern California, partially due to Aliso Canyon restrictions, could be causing part of the recent historical trend. It could also be useful to discuss gas hub differentials with the Council's gas price forecasting committee to see if the differentials used by the Council in AURORA should be altered. Other factors, including power system evening ramping needs in California, may be contributing to the recent historical trends as well. It could be interesting to study why there is a difference in seasonal prices when comparing recent historical prices to the *Midterm Assessment* forecast and make adjustments if appropriate.

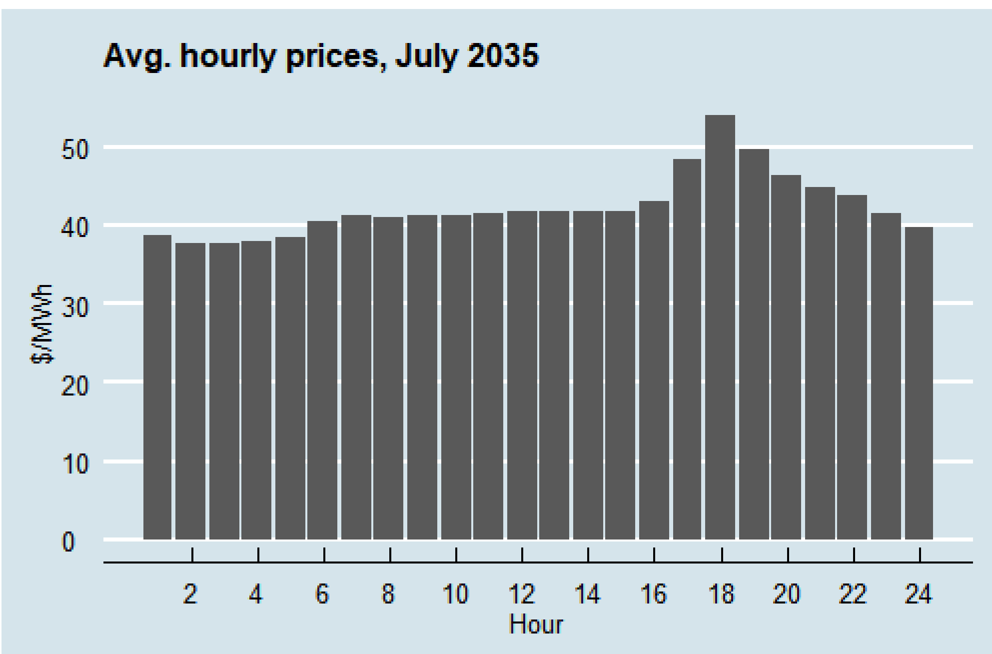
Hourly Question

Another question regarding price trends is the hourly shape in the *Midterm Assessment*. Figure 6 shows average hourly prices in July 2020 and July 2035 for all hydro years. PNUCC staff expected the shape of the evening price ramp to become more exaggerated going forward as more solar gets added to the Western Interconnection, but the forecast shows a flattening of prices going forward. It would be insightful to know why the prices are flattening out in the forecast.

Figure 6 – July average hourly power prices forecast, Council Midterm Assessment



Forecasted prices in 2020 are around $20 in the early afternoon and increase to just under $40 by HE 18, a change of nearly 100%.



In 2035, prices in the afternoon hover around $41/MWh, and increase to $54/MWh by HE 18, a change of just over 30%.