Northwest Power and Conservation Council
Meeting Minutes
April 7, 2021
Portland, Oregon

Council Chair Richard Devlin brought the meeting to order at 8:31 a.m. Council Members Jeffery Allen, Bo Downen, Doug Grob, Guy Norman, Patrick Oshie, Chuck Sams and Jim Yost joined by phone. The meeting was a webinar. The next Council Meeting is scheduled for May 4 and 5, 2021.

Reports from Committees

Fish and Wildlife

Member Allen, Fish and Wildlife Committee Chair, reviewed three presentations:

1. **Eulachon status update in the Columbia River**. In 2014, the Council adopted its Eulachon strategy. Early data in 2021 indicates a run size of over 4 million pounds and the larval counts are still increasing, indicating an improved run for this year. The management plan needs to be updated and the Washington Department of Fish and Wildlife is planning to initiate those revisions this year.

2. **Asset management recommendations for hatcheries and screens**. Staff recommends support for a set of nonrecurring maintenance requests. This comes about by implementing the Council's asset management strategic plan and is coordinated with Bonneville staff. They have received requests in excess of $2.6 million. Member Allen said they have a $500,000 placeholder to deal with needs. The final recommendations are for screens to receive $255,000 and hatcheries $238,000. The committee supports staff recommendations and will bring them to the full Council for approval in May. We need a long-term solution to maintenance funding.

3. **Lake Pend Oreille fishery recovery update.** The fishery has never been better than now. The program is an excellent example of a collaborative effort with BPA and Avista. Through the lake trout suppression effort, about 250,000 predatory lake trout have been removed. This has helped the kokanee and rainbow trout population to steadily increase. The kokanee population has risen from 250,000 to more than 12 million fish according to the latest surveys. There is a new predatory threat identified in the mid-2000s, walleye. A team of experts from the Great Lakes region was convened in 2018. They've mapped out a strategy to address walleye, and started an angler incentive program for walleyes including public outreach which has been successful. The collaborative effort of Idaho Fish and Game, BPA, and the

Council is a very successful model. It pays for the important monitoring and research that is needed.

Power

Member Oshie, Power Committee chair, discussed three presentations:

1. **Seasonality and market prices**. John Ollis addressed committee questions related to the wholesale price forecast used in the baseline. The focus was the impact of the expected high renewable build on the region and on the BPA. The model was used to forecast hourly prices for all hours of the day and by season.

   Member Oshie read the presentation summary:
   - Prices are expected to decrease over time, but there will be seasonal and daily variation increases. Volatility can be steep both up and down.
   - Daily price shapes no longer closely follow load; they follow load net renewables that are on the system. It's predominantly based on a large buildout of inexpensive solar.
   - Evening ramp hours are the largest price uncertainty area in spring and summer.
   - In winter and fall, the morning and evening ramps continue to both be areas of price uncertainty.

   He said the model also indicates that utilities in the WECC are building solar to meet summer peaks. That seems to be the most impactful with driving prices up and down. The model shows that there will be a massive curtailment of generating resources in the region during low-load and high-production periods.

2. **Markets for energy and capacity scenario.** The scenario looks at three possible market models: a WECC-wide market, a limited market reflecting current policies (but not built to reserve margins), and a market with no gas build limitations. The purpose is to look more deeply at how significant new resources builds in the West affect the Pacific Northwest's resource needs and how various market structures might impact resource sharing over a larger geographical footprint. The baseline build being used in the model is 429 GW of new generation, which meets the region's clean air policies and provides reserve margins and resource adequacy requirements. The WECC-wide market build is 367 GW, but it does not supply needed reserve margins and resource adequacy requirements. The limited market build is 213 GW. Planning reserve margins are missed almost immediately, and clean energy policy requirements are not met after 2030. The no gas limitations build 264 GW of new resources. In this model, the planning reserve margins are met consistently, but clean energy policy requirements are not met after 2030. The gas build is forecasted to be 3.5 times greater than the baseline.

   Limited market costs are projected to be lower in the non-Northwest Power Pool regions, but volatile. The organized market run indicates lower cost in the WECC, and the no gas limitation model suggests that there will be lower cost initially, but those prices begin to decline the further you get into the planning horizon.

3. **Bonneville Portfolio Scenario.** This looks at what resources are required to meet or reduce the administrator's obligation to provide power to customers in the region. They looked at BPA's energy efficiency program and how it evaluates targets. BPA's technically achievable energy efficiency over the plan's five years is approximately 500 aMW. However, this figure includes all resources within all cost bins, that may not be cost-effective during this period. This modeling work is a work in progress that will be further refined and brought back to the Committee for review.

   Member Oshie was happy to report staff's appreciation with BPA's assistance with this scenario and its willingness to work with staff, to review findings, and provide critical feedback.

Power Plan timeline – Member Oshie reported they are about six months behind due to COVID, changes the plan presented, and underestimation of project needs. They are making significant progress. This power plan is going to be very different than past plans, he said. We're going to see greater granularity of results and a regional outlook that captures the changes in renewable and conventional generation, and the impact of clean-energy policies.

Chair Devlin remarked that they would remain on schedule for the Power Plan. It's going to require a lot of commitment out of staff, members of the Power Committee, and those not on the Committee. We have no intention of extending this any longer, or it won't be the 2021 Plan, he said.

Public Affairs
Member Grob reported that the Council would proceed with Congressional Tour, August 16-19 in Whitefish, Montana. There was a discussion on whether to hold it every year or every other year. Member Allen stressed the need for an annual event to maintain relationships with NW Congressional offices. Member Grob noted that with recent retirements, we need to find highly competent people to organize and run this tour to be as successful as previous tours.

Member Grob talked about the 2021 Power Plan public outreach plan. It will be an ambitious outreach effort with use of video for the website, social media and stakeholder outreach, conventional press and media strategies, editorial boards, and public hearings, etc. in all 4 states as required by the Act. They will hold meetings as expected to go through the draft Power Plan. Member Oshie emphasized that perhaps the most important outreach should be with the critical entities and organizations that don't have the ability to follow the Council's activities closely. We want to be sure we communicate with state commissions, state energy offices, state legislators, and the Governor's offices.

1. White sturgeon status report for Lower and Mid-Columbia, and Lower Snake rivers

Mark Fritsch, project implementation manager, introduced Art Martin, Oregon Department of Fish and Wildlife; Blaine Parker, Columbia River Inter-Tribal Fish Commission; and Laura Heironimus, Washington Department of Fish and Wildlife.

Lower Columbia River White Sturgeon Population Status Update

Art Martin provided a white sturgeon population status update for the area below the Bonneville Dam. He traced the recent history of adult abundance (fish greater than 66 inches). Populations were very low in 2013, below the conservation status line. In 2020, they saw the population rise above the 9,000 threshold.

The data shows a general increasing trend for the legal-sized abundance of sturgeon since 2012. However, there is a decreasing trend in the metric of catch per unit effort (CPUE) which could be an indication that the estimates are overly optimistic for the legal population. In addition, there has been poor recruitment over the last several years, and if this continues, legal-size abundance will eventually decrease.

The data shows an increasing trend in adult abundance since 2013. Since the 2018-2020 period, adult abundance continues to grow above the desired status level in the conservation plan.

There is a long-term trend of decreasing juvenile abundance. The proportion of juveniles has been below conservation status since 2019.

Martin discussed the growth of the sea lion population targeting sturgeon. Consumption peaked in 2010-2011, so sturgeon could be being pushed out of an area where they were productive. There has been poor age-0 recruitment in the lower Columbia River for up to the last decade. Recruitment in the Willamette River has been marginally better, but not enough to increase relative juvenile abundance.

High sea lion abundance and predation is also of extreme concern, particularly below the Bonneville Dam and Willamette Falls locations where older age class white sturgeon reproduce.

Member Norman asked about the impact of Stellar sea lions below Bonneville Dam and whether the barge purchased their removal will have an effect. Martin replied it's his understanding that the barge and larger equipment will be purchased this spring and that it should help in the removal of sea lions.

Member Grob asked about sea lion removal in the Bonneville tailrace and if that effort made the sea lions move more toward the Willamette. Martin replied it's important to remember that sea lions are eating other species in addition to white sturgeon. As California sea lions started to be removed from Bonneville Dam, they observed a large increase of California sea lions moving into the Willamette. They hypothesize that the sea lion removal effort at Bonneville Dam was driving some of the sea lions toward Willamette Falls, and at the same time they saw increases in reproduction by white sturgeon.

Member Norman asked if there will be increased opportunities for harvest with an increased sturgeon population. Martin said they have been maintaining a commercial and recreational harvest in the Columbia based on the abundance of fish, but they will continue to take a relatively conservative approach to harvest rates. One of the only levers they have to manage sturgeon is to ensure enough of them are moving into broodstock, to invest in the future in terms of productivity for these fish.

Update on White Sturgeon populations – Bonneville, The Dalles, and John Day Reservoirs 2020 - 2021

Blaine Parker discussed Management Zone 6, the area between Bonneville and McNary dams. Reservoir populations are assessed every three years. Last year, they focused on The Dalles. Assessment is a two-part process: *winter tagging* and then *summer tagging and recapture.*

Bonneville is the most productive reservoir. There was tremendous recruitment in the mid-2000s, with over 334,000 sturgeon in 2009. There was a massive drop in the population within three years and another drop three years later. They are finding equilibrium with available habitat and current population size; there are reports of good body condition.

The Dalles, the smallest reservoir, isn't as productive as Bonneville. The population has been fairly consistent since the mid-90s until the past few years where there has been decline. They're managing for this with reduced harvest rates and continued tracking. John Day, the largest reservoir, ironically has the smallest number of sturgeon at 30,000. There has been no measurable recruitment for several years in John Day. In 2021, they will finish sampling in Bonneville and then focus on John Day this winter.

Conclusions for 2020:

- **Bonneville** – They've been challenged for many years, but they are finding equilibrium with available habitat and current population size; there are reports of good body condition.

- **The Dalles** – They are concerned with the population downturn, but recent recruitment will register with the next assessment in 2023.

- **John Day** – Declining abundance is likely to continue due to 14 years of little or no recruitment (22 consecutive years of sampling). This is a study site of the CRITFC Sturgeon Supplementation Master Plan. Parker anticipates that when the facility is approved and comes online, they'll be able to rebuild the population up to capacity for that large habitat.

White Sturgeon: McNary Reservoir and the Lower Snake River

Laura Heironimus discussed sturgeon from the McNary to the Lower Snake River dams. She mentioned the overall trend that the further upstream they go, the less productive the populations become and the less data they have on the populations. There are four major reservoirs: McNary, Ice Harbor, Lower Monumental, and Little Goose. They have assessed most of the areas only 2-3 times, and there are major gaps between assessments. She noted that no future funding had been identified for future stock assessments, and that the Independent Science Review Panel recommended funding proposals in all of these areas. Abundance estimates show a lack of abundance compared to other reservoirs.

Total abundance at McNary Reservoir and Hanford Reach in 1995 were 8,250. In 2011, it was 9,241, but 38% of that total was hatchery fish. She said the population has likely declined. It's tough to draw conclusions because of a lack of sampling.

She said the survival and growth of hatchery-origin sturgeon below Priest Rapids Dam are unknown. There are concerns of slow growth and recruitment failure. Again, there is inconsistent and sparse monitoring to draw any information from population trends. Also, there is difficulty assessing adaptive management actions.

All three Lower Snake reservoirs were closed to sturgeon harvest in 2015 due to the detected decline in sturgeon abundance and lack of recruitment. McNary Reservoir and Hanford Reach were closed to sturgeon harvest in 2020 due to a lack of recent monitoring data and poor evidence of natural recruitment. They expanded spawning sanctuaries through August 31, and expanded the sanctuary below Priest Rapids Dam to Vernita Bridge to decrease angler handling of spawning-sized fish.

Heironimus emphasized the need for more frequent monitoring on all of these areas, and said there are remaining uncertainties in population productivity and how hydro operations influence the population at all stages of development. They would like to work with the Northwest Power and Conservation Council to implement the Fish and Wildlife Program's white sturgeon recommendation for additional white sturgeon stock assessments in Snake River and McNary pools.

Member Norman asked if there were opportunities for additional monitoring, what would the highest priorities be? Heironimus replied it would be to have regular baseline stock assessments on a three-year basis. That is the best way to begin to evaluate the population's size.

Member Sams talked about his first frightening encounter with a sturgeon. What were their populations before the dams were built? Heironimus replied that before the dams, they were genetically a single population with access to the ocean. Now they are trapped populations. The earliest stock assessment was in the 1980s. There is no information from the 1930s.

Mark Fritsch said the priorities were embedded in the Council's resident fish and sturgeon review. They supported providing the baseline monitoring for those reservoirs in McNary and the Lower Snake, which Bonneville has not supported. It's also embedded in the Council's 2014 program and 2020 addendum.

Chair Devlin said some members might need to talk with Bonneville about supporting further baseline monitoring in these areas.

2. PGE Smart Grid Test Bed – Interim Evaluation findings

Tina Jayaweera, power planning resources manager, introduced Jason Salmi Klotz and Timothy Treadwell, Portland General Electric.

PGE's Flexible Load Portfolio

Klotz described activities behind the meter that can provide energy services. He discussed PGE's shift to a summer-peaking utility by the late 2020s. They are moving faster toward summer peaking than initially modeled. Its 2019 IRP forecasts that by 2025, there will be 211 MW of demand response available in summer and 141 MW in the winter. Most of PGE's demand response comes from residential customers which requires a great deal of engagement and repeated participation. There is an opportunity in co-development and co-deployment of energy efficiency — water heaters, HVAC systems, and ductless heat pumps all have the ability to shift load.

Treadwell described the $5.9 million research activity of the "smart grid test bed". PGE needs sustained engagement and savings from many customers — 66% participation to meet its goals. PGE received authorization from the commission to auto-enroll 17,000 residential customers into its peak-time rebate program. They have 20,000 total participants in the program.

The SGTB program runs through the remainder of the calendar year. Treadwell said auto-enrollment had increased demand response awareness. After summer 2019, PGE had 86% of its customers self-recording participation in a demand response event and 92% after summer 2020. So, they're happy with awareness and participation. Customers are primarily motivated to participate by financial incentives. They saw increased weight given to environmental considerations, particularly in carbon messaging.

PGE saw a 3x increase and customer migration from a peak time rebate over to its smart thermostat program for the testbed customers. Two key barriers to migration to the Smart Thermostat DLC program are 1. customers' perceived eligibility, and 2. concern about ceding control of the HVAC operation and concerns over comfort. He said they need better data about eligibility because they found they were asking some customers to participate who weren't able to.

Treadwell said there were misconceptions that they were doing the program for PGE’s benefit. Another finding is some customers don't want to spend a lot of time thinking about this. Others enjoyed the active participation and wanted hands-on control.

There was savings across all of the different customer segments within the testbed, however the savings was about half of outside the testbed for peak time rebate. Auto enrollees saved less than voluntary enrollees due to fewer opportunities for savings and being less engaged. There was a customer fall-off after events. Only 6% dropped entirely.

Underserved customer groups face disparities in housing, marketing, education, and decision-making power that make demand response less accessible. Findings are similar to the energy efficiency space. There also are issues with buildings. If the structure has inefficient equipment or doesn’t have a tight thermal envelope, customers’ ability to ride through an event in comfort is reduced. They heard from customers about their linguistic needs, and they responded by updating their marketing materials and engaging customers in their language of preference. They are working with community-based organizations to evaluate reaching underserved customer groups.

There are nine months left in the SGTB program, and they are happy with the results to date. In phase two, they will change the focus of the research from customer engagement within the context of the traditional demand response structure towards operationalizing these resources for a broader-based package of value streams. These resources as well as newer resources such as energy storage and electrical vehicle charging have a broader based opportunity to realize value. They’re going to start tapping into these value streams at the transmission and distribution levels. They’re also going to start using the testbed more aggressively to systematically field test concepts that are in the pre-product phase.

PGE worked with a number of stakeholders to submit for a DOE Connected Communities grant last month. They plan to install 1.4MW of flexible load capacity onto a feeder in North Portland and work with OSI and NREL to operationalize those assets. They also partnered with Community Energy Project to help engage underserved communities. This grant is budgeted at $11 million over five years (2022 – 2026). They are working to quantify the potential of DERs as operational assets.

Member Oshie asked if AMI is a required platform to accomplish the goals that they set. Treadwell replied they found the nature of demand response depends on the equipment behind the meter. The data were not sufficiently accurate to be able to effectively target customers. It's been important to have AMI data to analyze customer loads, segment them, and target customers based on the current available products.

Member Oshie asked what they see in the next decade regarding product technologies. Are opportunities turning on what manufactures are making available? Treadwell said it's a mix. We're seeing increasing capabilities and functionality from the manufacturers to provide grid control so that the push towards CTA-2045 water heaters is a big one. There is a need for increased sophistication from the utility side on operational dispatch and control. PGE is rolling out an ADMS (advanced distribution management system), and we're piloting enterprise DERMs (distributed energy resource management) as part of that system.

Member Oshie asked, from an economic standpoint, are there pressures to back off due to cost-effectiveness? Treadwell said their pilots are working toward enhancing cost-effectiveness. As we look at distribution operations and other capabilities demand response can provide, that will increase our cost effectiveness and our ability to incentivize customers to join programs. Right now, it's pretty tight, but the economics are going to change as we increase our sophistication.

Chair Devlin asked if PGE participated in building codes and standards at the state level. Has either of you testified before the legislature? Klotz said they have not. Chair Devlin expressed that it's unfortunate that given their experience they haven't been called into the legislature.

Member Grob referred to PGE's transition from winter to summer peaking and asked if it's climate change versus people just wanting to be more comfortable.

Klotz said their studies show an increase in city temperatures, which is the main driver for increased air conditioning load. It would be challenging to attribute summer increase directly to climate change, but there's a correlation. Longer, drier, hotter summers are driving people to air conditioning. What we see in a high electrification scenario (switching from natural gas heat to electric heat) over the next few decades is that we increasingly become a winter peaking utility again.

Chair Devlin asked how much of PGE's territory is in Willamette Valley. Treadwell replied it's overwhelmingly in the Willamette Valley, primarily from Portland Metro to Salem.

Chair Devlin told Member Grob it's likely a combination of climate and comfort. Air conditioning in homes is generally an expectation today. Member Grob said he would like to analyze the temperature increase. Treadwell said the pilot included North Portland, Milwaukie, Southern Hillsboro, a mix of old and new homes.

Member Sams emphasized the importance of diversity of buildouts and the need to do outreach through community action organizations. He asked how PGE is tracking and analyzing the DEI activities of the Community Energy Project and the Energy Trust of Oregon to understand the conservation values of diverse populations. Treadwell said they are tracking program data to understand program uptake. They have used English, Spanish, and Russian materials in program outreach. They are in a relatively early stage, but working with CEP and Energy Trust, it is a core goal to meet the needs of historically underserved populations.

3. PNUCC 2021 Northwest Regional Forecast

Jennifer Light, Regional Technical Forum manager, introduced Shauna McReynolds, Pacific Northwest Utilities Conference Committee (PNUCC) executive director. PNUCC's 10-year forecast serves as a good comparison with the 2021 Power Plan.

McReynolds described PNUCC and its membership. She said its Northwest Regional Forecast aggregates utility data in the Power Act footprint. She broke down the sources of information used, relying heavily on utility integrated resource plans.

Tomás Morrissey, PNUCC's senior policy analyst, reviewed winter peak, summer peak, and annual average loads over the last 11 years. He said winter peak loads vary yearly and without a trend. Summer peak loads are trending upward. Average annual energy is fairly flat with a slight upward trend. Morrissey then shifted back to forecasted loads. He emphasized that this is an aggregation of utility data. Individual utilities have a different story. They took 135 different load forecasts and put them into five different groups:

- 10 utilities forecast over 1.5% annual growth
- 7 utilities forecast 1.0% to 1.5% annual growth
- 22 utilities forecast 0.5% to 1% annual growth
- 82 utilities forecast 0.0% to 0.5% annual growth
- 14 utilities forecast annual load decay

McReynolds said energy efficiency remains a priority and an important part of utility integrated resource plans, and utilities continue to build programs for it. They expect to see 1,600 aMW of energy efficiency savings over the next 10 years. Morrissey mentioned that some utilities will see more energy efficiency than they’ve seen over the next 10 years, and some will see less. It depends on the utility’s unique situation. For Avista there is a lot more energy value for energy efficiency in Washington versus Idaho.

Projected demand response is up, most of it from Idaho Power's summer agriculture program. About 300 MW of new summer demand response is expected to come into the region over the next 10 years. A lot of that is from Portland General Electric. In the winter, there is around 300 MW of additional demand response expected.

Looking at the generating resources, McReynolds discussed how the resource mix changes over time and over seasonal peaks. Hydro remains a big piece of it. She noted that with the data, they’re able to see less anticipated wind capability in summer and winter peaks. The forecast represents what a utility is counting on in its planning process.

Morrissey talked about coal retirements in the Western Interconnection. There were 35,000 MW of coal in 2019, and this will drop to 12,500 MW by 2032. The pace of coal retirements in the last few years has been quickening. In the Northwest, there are about 4,000 MW of retirements projected in the next 10 years. Concerns over adequacy are driven by these coal retirements and some gas retirements. Some thermal units, such as Diablo, are going offline.

The recently acquired and committed resources coming to the region through 2023 are mostly renewables: 800-900 MW of wind and 700 MW of solar. There are also some smaller resources: a hydro contract, imports, and there is a 30-MW battery arriving in 2022-2023 as part of PGE's Wheatridge Renewable project. This is the first large battery in the region (over 10 MW).

McReynolds discussed the 6,000 MW gap of winter resources by 2030 and the 5,400 MW gap by summer 2030 that they’re seeing as retirements are completed in the next 10 years or so. This gap is a barometer for need, not a precise resource adequacy metric such as the Council's loss of load probability. What is being done to fill that gap?

Summer and winter deficits are starting to converge, and this is kind of unusual. Some utilities are peaking at different times than they used to. While the winter deficit is deeper, summer may become the more significant challenge.

- The greater West is summer peaking.
- CAISO is having summer challenges.
- Less hydro is available in summer.
- Summer loads are growing faster.

Morrissey talked about resources coming to the Northwest that utilities will use to meet their loads going forward. The ‘potential resources’ (not as firm as ‘committed resources’) utilities are putting in their integrated resources plans are mostly renewables: 5,000 MW from now through 2029. A big percentage of these are identified as ‘generic renewables’ which are renewables that don't yet have a defined fuel source, but should be identified in the next few years. There are 2,500 MW of dispatchable resources with a large percentage as batteries, a little bit as natural gas, and another big chunk is 'generic capacity' need with technology to be determined. The draft 2021 Power Plan baseline calls for 8,000 MW renewables by 2030. Next year, we'll see a few more renewables in utility portfolios due to the most recent renewable policies and cheaper renewable prices. So, we think it's in the ballpark with our 5,000 MW forecast, he said.

These potential resources help close the January and August gaps significantly. The data doesn't include imports from out of region or purchases from noncommitted IPPs, so there is likely more power available, but it depends on power markets. They are not too thrilled about leaning on power markets, particularly during the summer if other utilities have adequacy issues.

McReynolds summarized the main takeaways:

- Summer peak load is tracking with past forecasts; winter continues the pattern of lower and slower
- Energy efficiency remains a priority for utilities
- Coal retirements are a significant factor in growing adequacy concern
- Renewables are developing rapidly and make up much of utilities' expected future generation
- Resources are needed to meet peak loads

Some of the renewables are for meeting loads, and we know some of it is to meet policy requirements, she said.

For the 2021 Power Plan, PNUCC is paying attention to what resource builds the Power Committee is looking at in their scenarios. The success of the Power Plan is part of PNUCC's mission since 1980. McReynolds said that through the Power Plan, she hopes that the Council conveys the power system's complexity, acknowledges the reality of rapidly changing policies, and underscores the upcoming power system challenges.

Member Oshie asked what PNUCC hears from those on the ground (operators and controllers of systems) as to what they see as their biggest challenges over the next 5 years.

McReynolds said resource adequacy is a genuine concern. The Northwest Power Pool is doing work around that. PNUCC invited representatives to talk about what happened in other parts of the country last February, and they'll have other speakers talk about what could happen in the Northwest. There are concerns about how to get supply to demand as renewables increase. Utilities are working through how they're going to bring clean energy to fruition. There is a lot of conversation about what a market could look like in the Northwest where there are more participants in EIM and EDAM.

Morrissey said a common theme is that it will be a different power system with many renewables. It is exciting, but there are concerns about growing pains in switching to a different kind of power system.

Member Oshie said you hear what we hear. How do we get from where we are to where we want to be in the next five years? Is it likely we will have the necessary financing and buildout needed with retiring coal plants? On markets: Are regional utilities interested in participating in market activities, or getting involved in a more organized market that covers CAISO-style products?

McReynolds: This varies by person. One of the driving factors is the ability to connect with a broader set of options to meet your needs at any level. An element of a market is always the coordinated planning and use of the transmission system. The Boardman to Hemingway line is a 17 or 18-year experiment that hasn't happened yet. What is it going to take to get transmission built? There is a lot of push behind this part of it. There has been work done in the region to identify what the barriers have been in the past and how some of those barriers have evaporated. So is now the time we can make something happen? Governance of how it would be operated would be the biggest concern.

Member Grob observed that PNUCC is where he knows most of the executives and coffee talk is. On resource adequacy, what is the level of anxiety about having a significant event such as Texas?

McReynolds: There is increased anxiety. What's the next thing to happen? Heatwave? Polar vortex? Transmission line going down? I feel good about what the Power Pool is doing. We're working to avoid what happened in Texas. We’re going to share learnings between utilities and between regions so we’re better equipped to deal with an event.

Chair Devlin mentioned that PNUCC's planning horizon is 10 years, the Council's is 20. There has been lot of discussion about the impact of coal retirements. Not just in the Northwest, but across the entire WECC. This may be the decade of closure of coal facilities, but the following decade may be about the closure of gas facilities, or at least a curtailment of existing facilities. Has there been any discussion of this among PNUCC members?

McReynolds said that there is concern about how gas plants today or in the future can help get us to the cleanest future possible. Gas executives want to get to a clean future, and they have responsibility to their customers to manage. There is concern about how they can economically justify having a plant running to meet sporadic needs and doing it as cleanly as possible.

Chair Devlin announced this is Vice-Chair Downen's last meeting. He will leave the Council on May 3.

4. Summary of Coal Retirement Scenario Findings

Ben Kujala, Power Planning Director, prefaced the presentation by saying the scenario results are preliminary and subject to change.

Gillian Charles, Senior Policy Analyst, said the purpose of this scenario is to analyze the effect on resource strategies should there be 100% coal retirements in the region by 2027, and throughout the WECC by 2030. Already, 4,400 MW of coal retirements are scheduled for the next 10 years, which leaves 2,200 MW left on the system.

The majority of plants in the region have either already retired, or have a retirement date. There are four major coal units in the region with no retirement date: Colstrip 3 and 4, and Jim Bridger 3 and 4 for which retirement was accelerated for this scenario. There are differing opinions from multiple owners of what the end of useful life for these units is.

We've gone from almost 35,000 MW nameplate capacity of coal operating and available within the WECC in 2019 to under 15,000 MW by 2030 in retirements that have been announced or have already taken place. One of the parameters for the early retirement scenario is to accelerate (and vary) the retirements for all the coal units within the WECC to 2030.

Regarding the Colstrip facilities, there are varying ideas on what the future of these units looks like from the various owners' standpoints. Some owners have run IRPs that show an early exit from these facilities is economical. Other owners show the opposite, and want to continue running the plants through 2042. She mentioned a sensitivity study being conducted along those lines. The future of the Jim Bridger units is also uncertain.

John Ollis, Planning and Analysis Manager, noted that first set of results on the WECC come from the AURORA model. Regional results come from the GENESYS model. In summary:

- There is a more extensive WECC buildout from early coal retirements than in the baseline.
- Emissions and market emissions rates drop considerably in the early coal retirement scenario compared to the baseline.
- Market prices are slightly lower in later years than in the baseline.
- Regional needs shift from the early 2020s in the baseline to 2027 and 2031 after the early coal retirements.

The revised results show a more significant buildout from the system advisory committee:

Overall, the WECC build is 45 GW higher than the baseline:

1. CO_2 emissions drop by 38% in 2030; and 39% from the baseline by 2045 due to coal retirements.
2. Annual/seasonal planning reserve margins are less effective at efficiently enforcing adequacy on a power system with the following characteristics:
    - High penetration of renewables
    - Massive thermal retirements by 2030
3. Clean requirements are more expensive to meet than in the baseline.

There will be a significant solar + battery buildout and a lot of other resources to replace the generation. It's a kitchen-sink approach.

Under this scenario, more resources were built where the coal units were retiring, and more units were retiring in the Northwest Power Pool area.

- 8 GW more resources would be built in Southern California and Arizona.
- 37 GW more resources would be built in the Pacific Northwest, Mountain West and Canada.

A higher share of costs is borne by the Northwest because there were more builds in the Northwest. Along with the large buildout comes massive amounts of renewable curtailment. Also, Ollis said it's harder to meet clean policies in the late 2030s than he would have expected.

Buildout observations:

- The current buildout is less adequate and less successful at fulfilling policies than the baseline run. This build reflected SAAC suggestions.
- This will likely show more price volatility and a lower market emissions rate.
- The buildout will likely show a less surplus market in the needs assessment, with more build in the Pacific Northwest.

Pricing and Emissions Summary for the Early Coal Retirement Scenario

- Prices at the mid-Columbia go lower than baseline on an annual basis
    - More renewable builds in the Northwest than in baseline
- Slightly less seasonal price variability than baseline.
- Avoided CO2e Emissions Rate decreases faster than the baseline and ends up about 50% of the baseline market emissions rate.

Conclusions

- Bigger, more diverse WECC buildout backfills for early retirements
- Less emissions and lower market prices than in baseline
- Increase in regional needs coincides with the early coal retirements

Baseline Conditions Update
Ben Kujala, Director of Power Planning discussed the change in coordination between RPM and GENESYS models. The biggest thing that they found out that caused them to revisit the baseline conditions was that the coordination between RPM and GENESYS was overstating the resource need from RPM. Based on this, an updating the Baseline Conditions was appropriate.

Results from the update to Baseline Conditions reduced the resources needed for adequacy and a lead to some significant changes, including:

- No build of natural gas generation.
- No demand response is selected.
- Fewer renewables and energy efficiency are built.

We continue to see renewables being built as a strategy, Kujala said. Renewable curtailment won't go away, however. It continues to be a persistent message in the model.

Kujala said there is a little bit of an immediate adequacy need, but after the build out of renewables and energy efficiency is acquired, there are minimal adequacy needs throughout the entire study. Overall, it's an adequate system. Given the large buildout in the WECC, the system would be adequate because they would be able to get cheap power from the market. If that build does not occur, they would test that result in future scenarios. Even though there is no adequacy need, they are seen a slow derate to what the system can do throughout the entirety of the run. Even with this and critical water reduction forecasted over the next 20 years, given the build in the system and the signal from GENESYS, this is sufficient to meet the need.

Chair Devlin observed the renewable build is 4.9 GW. How much lower is that than the prior analysis, and how does that compare to the analysis that is already in IRPs as discussed in the Power Committee Meeting? Kujala said it is lower, but it makes it more consistent. IRPs shows that people are prepared to build at that level.

After talking about changes in the baseline, Kujala covered early coal retirement scenario takeaway. When taking coal plants out of the region and changing the market prices that go along with that, they saw:

- Change in timing of renewable builds, but not necessarily a change in magnitude
- Increase in natural gas generation build
- Substantial near-term reduction in greenhouse-gas emissions because the new thermal plants are run less often.
- A 6% increase in residential bills over 20-years.

Other results include:

- A slight reduction in energy efficiency because of the cost of it relative to the adequacy it provides
- Renewables shift to build quite a bit earlier
- Thermal generation is built to replace regions retiring coal fleet
- Substantial GHG emissions reductions regardless of the near term natural gas build
- Fewer exports after regional coal fleet retirements.
- About 6% average increase in bills over 20 years

Member Grob said that early on, there is a rapid build of gas plants. Then thermal is needed less. Are these more modern plants less expensive to build, and does this make economic sense for power producers? Kujala answered, yes. They always put forward an adequate portfolio. This is the cheapest way to meet the adequacy need. The cost is borne by the rate payers.

Vice-Chair Downen asked if Members are getting a Power Plan draft by July. When will these scenarios come together as a package? Kujala replied they're working towards the July date. The scenario analysis is the last piece. They have two substantial pieces left: the Bonneville scenario and the decarbonization pathway.

Chair Devlin asked about the nameplate capacity of thermal generation and the level a plant would actually produce considering coal retirements and renewable buildouts etc. Kujala said they need more GENESYS analysis, but it's 20 percent or less mostly to support morning and evening ramps.

Member Grob observed the thermal build on slide 51 and asked if these are cheap combustion turbines that run for a short time, so the cost and amortization aren't as high as they used to be. Kujala mentioned that the specific technologies haven’t yet been selected, but they would be gas units that are made to be the most flexible in responding to a peaking need.

5. Council business

Council approval of the March 2021 Council Meeting minutes.

Vice-Chair Downen moved that the Council approve for the signature of the Vice-Chair the minutes of the March 10, 2021, Council Meeting held via webinar, as presented by staff.

Member Grob second.
Motion approved.

Election of Vice-Chair

Vice-Chair Downen was appointed in July 2019, and was given a plaque for his service. Chair Devlin praised Vice-Chair Downen's work, and Members Grob, Oshie, Norman, Allen shared their compliments and appreciation.

Vice-Chair Downen thanked Governor Bullock for the appointment, and expressed that he was thankful to have met current and past Council Members. He praised the Central Staff and State Staff for their great work.

Vice-Chair Downen nominated Council Member Guy Norman to be the Council's next Vice-Chair, assuming that office effective May 3, 2021.

Member Oshie second.
Vice-Chair Downen explained why Member Norman is a good choice.
Nomination approved.

Public comment

Jim Waddell talked about negative pricing associated with the hydrosystem and the environmental impacts of dams. We need to be open to breaching the Lower Snake River Dams this year, he said.

Chair Devlin talked about the departure of Council members and lamented that he has had to say goodbye online. He is hopeful that by summer, these meetings can be in person.

Chair Devlin adjourned the meeting at 2:01 p.m.