Northwest Power and Conservation Council
Systems Analysis Advisory Committee
August 5, 2020

John Ollis, NWPCC, welcomed the group at 9:30am and stated that the day's agenda may shift as needed. Chad Madron, NWPCC, explained the features of Go-To-Webinar. Ollis explained that the July SAAC meeting was cancelled due to extra work needed for regional loads.

Adequacy Reserve Margins and Associated System Capacity Contributions
John Fazio, NWPCC
John Fazio, NWPCC, discussed two planning parameters: the Adequacy Reserve Margin (ARM) and the Associated System Capacity Contributions (ASCCs) for new resources. Fazio explained the ARM and ASCC, including how each are calculated and used within the Regional Portfolio Model for the Power Plan, and shared some results for the ARMs using climate change data.

Tomás Morrissey, PNUCC, asked if the values about to be shown include the updated loads [Slide 7.] Fazio answered yes.

Sashwat Roy, Renewable NW, asked if there was any consideration for typical hybrid projects, like PV/wind paired with four-hour batteries [Slide 10.] Ollis answered that there is a consideration for new resources, but not in the ARM in chat, adding that there are not many hybrid resources in the existing regional system yet. Fazio added that that this will be discussed during the ASCC portion of the presentation.

Rob Diffely, BPA, asked how the wind capacity contrition was calculated [Slide 9.] Ollis answered, in chat, that staff calculated the average peek contribution between the top two hours of load in the quarter. He wrote that this is an expected contribution over all of the climate change scenarios in those two hours in the respective quarters.

Diffely then asked what the resulting capacity factor on peak is. Fazio answered that for quarter one in the existing wind fleet it's 26%, quarter two is 35%, quarter three is 33% and quarter four is 27%. Fazio added that this is not all Gorge wind and is split over three sites.

Nora Xu, PGE, asked if the capacity factor is calculated for wind/solar separately or for all of the solar plus all of the wind fleet aggregated together. Ollis stated that the wind and solar fleet are aggregated when determining total expected capacity contribution in the calculation even though the wind has three different regimes contributing to the diversity of the existing resource capacity contribution.

Silvia Melchiorri, PGE, asked what loads are being used and if they are an average of your climate scenarios. Fazio responded that staff is running each climate change scenario separately and aggregate results together. Ollis added that wind is not averaged in these studies. Fazio stressed that each climate scenario has projected wind speeds but here they are aggregated.

Diffely wrote that he has not seen anything that high on existing, individual plants in the BPA BA. Ollis wrote that he will check and make sure the results are updated after updating the Climate Change wind. However, he continues, the number you see definitely benefits from all the diversity of the regional wind fleet at peak times. Ollis added that the wind will align with the RPM.

Melchiorri asked if staff designate specific resources to provide energy and capacity. Fazio answered no, saying this is an analytical calculation and not resource specific.

Rick Williams, Portland State University, asked if the 2021 and 2022 plans include energy from California [Slide 25.] Fazio answered that the Adequacy Assessment studies include 2500MW of spot market availability during the winter and 0 during the summer with the assumption that we can import 3000MW during off peak hours any month of the year. He acknowledged that for the 2021 Plan assumptions will change to 2500MW available all year except for hours 17-22 during the summer. He said the in-region market supply (IPP resources) are fully available all year except during maintenance and forced outages.

Morrissey asked if Q1 on [Slide 25] is Oct-Dec or Jan-March. Fazio answered its January-March.

Michael McCoy, independent, asked if the RPM, which is linear, can take the multi-surface construct for the ARM into account when selecting the mix of resources. Ollis said yes and explained the process, noting that while it is not perfect it does get you to a reasonable place. McCoy confirmed that the RPM's driver is up-to-date. Fazio confirmed that the RPM was amended to use the ASCC array this year. McCoy asked if the RPM's solver was developed in-house or is an industry product. Ollis answered that the solver is from Optiquest but there are many industry solvers that could be used.

Williams asked how climate-change-driven and wildfire-influenced preemptive Public Safety Power Shutoffs affect resource adequacy. Fazio answered that they don't include wildfires as this is a long-term look. Fazio added that an event that happens every year in anticipation of wildfires would be included.

Williams argued that Climate Change driven wildfires no longer look like a one-time event and any long-term planning should consider that reality. Fazio countered that out-of-region import assumptions are quite conservative to start.

Williams stated that the issue exists inside the region as well, pointing to Pacific Power's proposal of pre-emptive procedures for Southern Oregon and Hood River County. Fazio said that should come in through the Load Forecast and offered to investigate. Ollis said this is being considered and pursued but the underlying data needed will not be ready for the 2021 Plan.

Fred Heutte, NW Energy Coalition, asked if Demand Response has the same effect as Energy Efficiency in the context of [Slide 26.] Ollis explained how resources have been categorized, and referenced a chat question from Tanya Barnham, Community Energy Labs, that asked, how is it "better" for Resource Adequacy or compare with previous Plans. Ollis then pointed to [Slide 19] to show the difference between stand-alone Capacity Contributions versus portfolio-level Capacity Contributions, saying the portfolio-level look does a better job.

Ollis then addressed Heutte's comment, saying that DR and four-hour batteries have a similar Capacity Contribution but DR does not have energy in needed hours. Ollis then explained that renewables and DR push the ASCC down in different ways.

Heutte asked if "Combo Winter-Summer DR" on [Slide 19] means looking at winter-only, summer-only and DR that can do both. Ollis said yes, emphasizing that this chart is just stand-alone with the existing system. Ollis cautioned that EE can cannibalize DR.

Heutte noted that Montana Wind appears to be the closest match. Fazio said these are historic numbers and will change when the Climate Change data is applied.

Barnham confirmed that the ASCC value is the derate applied to particular portfolios [Slide 23.] Ollis answered yes. Barnham asked how the model is reacting to this. Fazio moved to [Slide 26] to show limited results with historic data, adding that he still needs to do it with Climate Change data. Barnham asked for the table with complete, as opposed to limited, results. Ollis cautioned that this is historic hydro test data and the Climate Change data will change the results. Ollis added that this is region specific and if California did an ASCC study it would look very different.

Barnham asked for information about the min/max combination values that were used for each resource. Fazio said he aimed for a full range as doing this in increments would result in too many runs, so he drew a straight line between the min/max. Barnham agreed that this was the most reasonable approach.

Barnham asked if the Quarters correspond to the seasons. Fazio answered yes, Q1 is January through March. Fazio then said he will put the spreadsheet for [Slide 26] in an accessible place on the NWPCC website.

Update on WECC-Wide Clean Energy Policy Analysis
Slides by Gillian Charles, NWPCC
Presented by John Ollis, NWPCC
Ollis presented the aggregate, individual, state pseudo clean policies both to the Region and WECC-wide to be incorporated into the models for the draft 2021 Power Plan. Ollis walked through the aggregation method, the resulting aggregate targets, and the effect of the aggregation on the targets and what is modeled in AURORA and the RPM.

Xu asked if [Slide 9] enforces the regional Pacific Northwest clean plus RPS target only or in addition to the different state targets over time. Ollis said this will be addressed in the methodology of the electricity price forecast, but previewed that in AURORA they've switched to just doing the RPS target and clean target for all of the WECC, adding that using multiple targets caused weird results.

Diffely asked if Clean includes hydro and nuclear while RPS is just new renewables like solar, wind, etc. Ollis answered yes, saying it will be covered more fully in the AURORA buildout methodology.

Sibyl Geiselman, Avangrid, asked how the contribution of nuclear power is observed in the clean targets. Ollis said they allowed it.

Jason Sierman, Oregon, asked if any of this presentation presumes that there are no “dirty” policies i.e. policies that would prevent adopting jurisdictions from receiving clean power. Ollis didn’t know. Sierman said the pseudo clean target of 20% might leave space for people to receive non-clean power. He also referenced news stories of policies that try to extend the life of coal plants.

Heutte wrote, in chat, that he was a bit uncomfortable with the term pseudo-clean, saying that it’s not that the resources are pseudo clean, but more about how binding the targets are, adding that RPS is very binding while other policies may be less so. Ollis stated that he and Charles can adjust the expected achievement percentage. Heutte recognized that there’s a range of targets and they are complicated. He complimented Charles on her comprehensive effort.

Ollis said this work puts attributes on produced energy as people now care about them. He added that utilities and municipalities are taking these policies seriously and this is a way for staff to have an aggregated target. He assured Sierman that the 20% is well represented in the models.

Geiselman asked how California in-state restrictions are handled. Ollis said they are not explaining that staff has punted on it as AURORA captures that CA prefers to build renewables. Geiselman asked if changes to the wheeling rates and emission factors over time are being modeled, recognizing that the hurdle rates may go down as the region becomes more green. Ollis said that they are not as dynamic as they should be and he is mostly looking at Mid-C prices. Ollis added that emission factors are dynamic.

Geiselman noted that the timing of in and out flows from California can make a big difference on the reliability side. Ollis asked that she bring this up later in the afternoon when he shows the buildout.

LUNCH

Review of Price Forecast and Avoided Emissions Rate Methodology
John Ollis, NWPCC
Ollis reviewed the pricing study methodology, including input updates of note for discussion.

Xu asked if additional retirements of existing resources that weren't announced through the Long-Term Capacity Expansion Logic were allowed [Slide 7.] Ollis answered no, AURORA is not allowed to drop existing resources.

Morrissey asked if there are any plans to run sensitivities with a more aggressive retirement schedule. Ollis answered not in the baseline but possibly in an AURORA policy scenario if there is interest. Ollis then called for input and suggestions about what to test, offering to roll it into a market scenario.

Xu asked about the carbon price assumptions in different regions in the base case. Ollis stated that, on a high level, California's and BC's existing carbon policies are included while the social cost of carbon has been backed out. He added that the RPM usually doesn't include carbon damages external to the region. Ollis added that cost of carbon might not be included in the price but show up in the buildout. Ollis stated that this will also be discussed later in the day.

Sierman asked about the mix of retired CCCTs versus SCCTs in California and if there any lessons to be gleaned for the Pacific Northwest. Ollis said that it looks like they are retiring baseload for some more flexible units but didn't know if it's an overall strategy.

Morrissey asked about limitations, wondering if the model is building gas units in places like Alberta specifically to export power [Slide 9.] Ollis answered no, doubting that hardly any would make its way to the region. Morrissey then asked about Wyoming and Utah. Ollis said that is different, acknowledging that their gas builds could influence regional adequacy.

Sierman asked to tease out the restrictions for CCCTs versus SCCTs in AURORA, saying it seems counterintuitive noting that they are more efficient. Ollis said it's complex and listed some issues related to operational constraints and what can be modeled with the time available. Seirman agreed that there are tradeoffs. Ollis thought both technologies could fit based on regional economics and regulatory environments.

Heutte pointed to seeing no interest in new gas when looking at IOU's RFPs. He agreed that it is conceivable to see new gas, but unlikely.

Williams stated that the existing datasets represent the current Columbia River Treaty, noting that negotiations for renewal may have a range of potential affects on hydropower availability and flexibility. Because of this, he asked for a range of potential treaty outcome to be modeled in a sensitivity analysis. Ollis said it could be done but wondered about the timing for the 2021 Plan, adding that right now the model shows persistence of the Treaty.

Williams argued that the treaty is moving to incorporate bio-system maintenance along with flood control and power production. He said this will almost certainly affect flexibility of dispatch and needs to be explored as policy and risk. Ollis said it will probably not be in the baseline scenario but he will bring this up at the next Council meeting.

Xu pointed to the optimization CDS tables, saying AURORA advised her that the CDS tables only work with their traditional commitment methodology [Slide 14.] Ollis called that interesting and asked what version she is using. Xu answered 13.0.1049. Ollis said he runs 13.4.1038 which is more recent but will double check the issue.

Geiselman asked if the "hydro training wheels" were checked so see if they were overly restricting hydro availability at the head of the duck curve, i.e. late evening off peak. Ollis answered no adding that it looks like AURORA is unrestricting itself during hour 17-22.

Wholesale Price Forecast and Avoided Carbon Dioxide Emission Rate
John Ollis, NWPCC
Ollis presented very preliminary results for the baseline WECC buildout. Ollis stressed that this is likely NOT staff's proposed WECC buildout as there are concerns; therefore, presentation teed up "art of modeling" questions for SAAC feedback and advice to improve the buildout for the price study. Lastly, Ollis provided a brief avoided emissions rate methodology update.

Geiselman asked if this is the amount of storage actually being utilized in the model or is it just being build for reliability [Slide 7.] Ollis answered both, pointing to a strong economic signal and planning reserve margins.

Melchiorri asked about the peak value of wind and solar, wondering if it is materially different from 2019. Ollis answered no, saying he uses dynamic peak credit for wind and solar.

Heutte noted that policy doesn't work in a straight line and guessed that as California absorbs electrification policy there will be increased attention paid to load management [Slide 10.] He thought the situation might look different next year but acknowledged that you have to work with the data you have. Ollis thanked him and stated that forecasts come from the CEC.

Morrissey asked if states with clean policy, like California, can still import natural gas power and maintain their clean status. He added that this seems like a lot of gas and unlikely to be built especially five years out. Ollis agreed, saying that's why he's presenting this.

Barnham brought up energy management, saying it's a widely discussed topic on CEC calls. She suggested a closer look at the interplay between load growth, advanced demand response and grid-connected buildings. Ollis lamented that these are average loads and the peak loads are worse adding that batteries being picked may be a proxy for demand-side management. Ollis said his real concern is the selection of so many thermal plants, adding that it seems out of touch.

Barnham said talking on the fly might not be helpful as she's having a hard time grasping the magnitude of the issue and suggested talking offline. Ollis said because of technical difficulties he's presenting more intermediate results. Barnham asked the Ollis share any updates with her and other interested members. Ollis said that's his strategy.

Heutte commented that it's unlikely California would do new gas for a variety of reasons including gas supply and pipeline issues. He noted the large increase in batteries. Heutte said California has many options that the model does not know about and appreciated the intermediate look.

Xu agreed that she doesn't traditionally think about the gas supply and it might be good to start. She then asked if Ollis saw renewable units max out during the buildout run. Ollis said they could have built more renewables and offered to dig further into wheeling rates.

Xu noted that in the past she's seen AURORA not meet the optimal solution when it runs into some of these kinds of constraints.

Melchiorri asked if the Pacific Northwest hydro is significantly more constrained in the summer compared to the 2019 setup. If so, she thought it might have triggered a massive capacity shortage to deal with in summer because of solar generation in California and the Southwest. Ollis agreed to some extent.

Melchiorri then said if the solution is too complicated AURORA might not have found it and released the constraints. She asked if Ollis is using GUROBI or MOSEK as MOSEK leads to more unsolvable constraints. Ollis said he's using GUROBI and thought the Climate Change hydro might be causing this issue and suggested picking a different Climate Change data set.

Sierman offered to talk about this more offline. He moved to the battery buildout on [Slide 7] asking if the solar with battery and four-hour battery are stand-alone. Ollis answered yes, noting that solar with battery has a slightly higher fixed cost and different shape. Sierman said the hybrid resource charges when the renewable is available while the stand-alone battery charges anytime. He then asked why there was such a huge wind drop off. Ollis said this will be addressed on [Slide 11.]

Heutte said that solar plus battery can only be charged by solar right now but that rule can roll off over time. He thought this could be a good topic for the update.

Xu commented that it would be cheaper for the system to build more renewables and curtail them if curtailment is free [Slide 16] and suggested looking for something that may be limiting this unintentionally. She asked if Ollis is using bit adders for renewables or if there is any scarcity pricing mechanism. Ollis said he is using a bit adder with 2016 dollars, adding that it inflates over time but still remains negative. Ollis wasn't sure about scarcity pricing and offered to look into it.

Geiselman questioned this level of buildout in relation to the high electrification in California scenario from a development perspective. She thought that level of demand increases coupled with siting challenges made it seem unsurmountable. She suggested checking for double counting between EV demand and the CEC forecast. She also suggested looking at some of the shifting and shaping that might be planned via demand side measures as EV and high electrification loads increase.

Geiselman stated that she's run into some of the same issues with her modeling and concluded that four-hour duration storage can't really cut it and points to hydro as storage resource. She suggested looking into things that influence hourly shapes in more detail, noting that last year's EV hourly shaping from the CEC didn't look well thought out.

Ollis agreed, saying he used the updated hourly shape forecast, but they end up as a stretch in the long term which creates a larger amplitude. He suggested lowering the expected peak in AURORA for California as a solution.

Roy asked if it was possible to include Carbon Capture and Storage costs into the gas builds. Ollis answered not with the compressed timeline but will suggest it to Charles for the Pathways to Decarbonization scenario.

Eric Graessley, BPA, voiced support for straight-line smoothing to avoid a cliff. He also thought something was very off with the results and suggested checking the peak hours, zonal output, SMP max demand. He said it's good to increase max iterations but a bad sign if it's going past 25 to 30 iterations. Ollis thanked him.

Morrissey thought the load change on [Slide 13] seemed like a stretch as well and suggested reverting back to the old load forecast. Ollis said this is an updated load forecast from the CEC, commenting that it's well sourced. He added that he thought demand-side measures are incorporated into the CEC forecast. Ollis agreed that results for 2030 and beyond come from a different source and suggested not going on the high electrification trajectory for now.

Morrissey asked Ollis to share the earlier and near-term forecasts. Ollis said yes, adding that some results have to do with vintage, pointing to AURORA forecasts that haven't been updated in a few years.

Graessley asked if there are plans to make any changes to the transmission topology over time. Ollis answered with a resounding NOPE and asked for thoughts on how to do it and how that might help the problem at hand. Graessley said he is exploring it and is looking for recommendations.

Geiselman suggested double checking the CEC as their spreadsheet sometimes has counterintuitive signs for different components that could lead to double counting. Ollis said he will dig into the load forecast a bit as it's a big driver.

Brief Wholesale Power Price Study Update
John Ollis, NWPCC
Ollis stated that this will be brief as the buildout is not yet nailed down.
There were no comments

Ollis ended the meeting at 3:30.

Attendees via Go-To-Webinar

Tanya Barnham	Community Energy Labs
Dhruv Bhatnagar	PNNL
Leann Bleakney	NWPCC
Frank Brown	BPA
Rachel Dawson	Cascade Policy
Rob Diffely	BPA
Bo Downen	NWPCC
Karen Flynn	Idaho Power
Villamor Gamponia	Seattle City Light
Sibyl Geiselman	Avangrid
Andrea Goodwin	NWPCC
Eric Graessley	BPA
Jared Hansen	Idaho Power
Fred Heutte	NW Energy Coalition
Mike Hoffman	PNNL
Elizabeth Hossner	Puget Sound Energy
Charlie Inman	Puget Sound Energy
Torsten Kieper	BPA
Shirley Lindstrom	NWPCC
Jim Litchfield	independent
John Lyons	Avista
Michael McCoy	independent
Jennifer Magat	Puget Sound Energy
Garrison Marr	Snohomish PUD
Shauna McReynolds	PNNUC
Ian McGetrick	Idaho Power
Silvia Melchiorri	PGE
Tomás Morrissey	PNUCC
Ahlmahz Negash	Tacoma Power
Elizabeth Osborne	NWPCC
Patrick Oshie	NWPCC
Selisa Rollins	BPA
Sashwat Roy	Renewable NW
Kathi Scanlan	WA UTC
Jason Sierman	Oregon
Tyler Tobin	Puget Sound Energy
Rick Williams	Portland State University
Cindy Wright	Seattle City Light
Nora Xu	PGE
Zhi Chen	Puget Sound Energy

Brian Dekiep	NWPCC
Alaine Ginocchio	Western Energy Board
Barbara Miller	US Army Corp of Engineers
Will Price	EWEB
B. Fitch-Fleischmann	Northwestern
Rebecca Smith	Oregon
Jim Woodward	WA UTC
John Ollis	NWPCC
Chad Madron	NWPCC
John Fazio	NWPCC