Northwest **Power** and **Conservation** Council

Minutes for Systems Analysis Advisory Committee
July 17, 2025

John Ollis, NWPCC, began the meeting at 9:30 by asking Chad Madron, NWPCC, to explain how to best interact with the Zoom Webinar. Ollis then called for introductions both in the room and on the Zoom Webinar before reviewing the agenda.

OptGen/SDDP Methodology Discussion

Ollis noted that the day's work should feature robust discussions on methodologies. Encouraging the SAAC to weigh in with give valuable feedback, Ollis pointed to icons on presentation slides designed to cue these discussions. He demonstrated this practice by showing a slide that said "Pie is objectively better than cake" [Slide 4]. Vigorous, full-throated debate ensued.

Jared Hansen, Idaho Power, agreed that the WestTEC work needed to be explored [Slide 5]. Aliza Seelig, PNUCC, pointed to PNUCC's work with WestTec, calling it important, calling it a great place to start.

Seelig asked if [Slide 7] illustrated capacity expansion or both expansion and dispatch. Ollis said all of the Council models have a similar zonal set up, so this would be for all of them, Aurora, GENESYS, and OptGen/SDDP.

Seelig said she is thinking about capacity expansion first, wondering if this approach would help mitigate overbuild. She asked if staff would vary inputs by season or some other metric, saying that complexity matters but she was not sure by how much.

Ollis said emissions pricing does affect Aurora and he suspects that incentivizes builds that are cleaner than the current system to some extent. Ollis thought that emissions pricing will increase builds, but in practice some constraints on the model mitigate the overbuild issue.

Ollis then said because the clean policy target is often annual, it wouldn't work to make it seasonal. He said this could be a case where staff do something simpler in Aurora and more sophisticated in the regional modeling.

Alexandra Karpoff, PSE, confirmed that emissions pricing will be applied to individual emitting units and additionally apply emissions costs to imports. She asked if this is double counting. Ollis answered that it would only be applied to imports into the state. He said Washington to

Washington transfers would not have an associated emissions price. Ollis admitted that this was not perfect, but a good estimate.

Tomás Morrissey, NWPCC, added that it only applies to zones with emissions pricing leading to no pricing for a Wyoming unit serving Nevada.

Karpoff said PSE is working with Aurora now and found that emission pricing drastically effects the build out. She said she sees the emission pricing put a dramatic reduction on thermal builds, which is the opposite of what Ollis found. Karpoff also reported that they are not seeing a lot of overbuilds.

Ollis thanked her, adding that the studies that shows increased builds are WECC-wide studies, not local or regional. Karpoff stated that she is talking about PSE's WECC-wide, regional model. Ollis said he will be showing an Aurora build out later in the presentation that he would like her comments on.

Carla Essenberg, BPA, asked how the percentage for power imported with and without carbon is determined. Ollis explained a calculation that includes the Council's demand forecast, state policies, and price premiums.

Essenberg was still confused, asking if this means that any load in a state without carbon policy would be served by emitting generation. Ollis answered yes but said the model captures clean policies and goals.

Dave LeVee, PwrCast, said he is a proponent of having DR respond to pricing as it is a way to influence customers. He called this an integrated dynamic perspective built into Aurora. Ollis said staff's Aurora assumptions model existing DR but don't build out DR or EE. LeVee argued that there needs to be an integrated perspective and not two models doing their own thing.

LeVee said that Aurora measures emission levels at any time giving a pricing feedback by region or area [Slide 8]. Ollis agreed, saying the slide addresses a specific state target and pricing.

Fred Heutte, NW Energy Coalition, called emissions accounting mind bending and approved of staff's efforts. He wished that e-tags carried information saying it would make this effort easier. Heutte then asked what California's carbon price work, which should be completed in October, means for this work. Ollis thought that October would be late, adding that the Council's build is very similar to the CEC's projection.

LeVee thought it would not be good to report differentials on key objectives but instead incorporate price elasticity, so customers have options [Slide 9]. He suggested reporting investment tax credits or subsidies from power cost adjustments.

John Crider, EWEB, shared that he had the same thought as Ollis, saying he ran capacity expansion without the ITC in the fixed resource cost. Crider reported that this didn't affect the buildout much, confirming Ollis's instinct.

Ollis said adhering to state policies and goals will have a trajectory. Crider explained his approach of using the shadow price to find the Rec price, adding that he likes Ollis's approach better.

David Clement, NEEA, asked if all of the scenarios will be adjusted for what is coming in the Big Beautiful Bill. Ollis said this is a struggle for staff as well. Clement said staff has been disciplined in following state policy wondered if that discipline would be applied to federal policy as well.

Jennifer Light, NWPCC, asked committee members to recall that staff use the tax credits as a proxy for uncertainty in prices. She pointed to a scenario that removed the tax credits. Light thought staff would not move away from that frame, but different sensitivities might shift.

Ian McGetrick, Idaho Power, reported including a High Resource Cost Scenario in their IRP by removing tax credits. He said the analysis was completed before passage of the bill. McGetrick expressed curiosity about Oregon's HB2021, the 6% revenue requirement cost cap, and the repeal of tax credits. He thought this would result in a significant increase in the cost of compliance, wondering if this should be explored in a scenario.

Ollis said in the past staff have taken a vanilla view because of modeling challenges. He said staff should have internal discussions about this and bring the issue back at another meeting. McGetrick reported a conversation with a consultant that said their base assumption is getting close to renewable goals but not meant them.

Seelig approved of this policy discussion. She wondered if staff plan to talk about barriers to building because of transmission and the amount of NIMBYism. Seelig asked how staff will deal with this. Ollis answered that staff are fleshing out their resource and transmission risk scenario which should address this issues. Seelig approved, reminding herself and the room that no one scenario is the reference.

Heutte spoke of some realities of the BBB, saying costs going up and orders diminishing will result in marginal changes. He added that the equipment is out there and the amount of resource available is a known quantity. Heutte said the question of who will pay will change, calling the federal money more of an enablement. Heutte summarized by saying he didn't think much would change for the 9th Plan. He admitted that costs will go up, but resource will be available.

Questions

Heutte asked about the comfort zone and what the region might gain or lose by going to 30 or 3,000 model runs as opposed to the proposed 300. Ollis said staff are concerned about hydro risk while the other futures represent demand outcomes. Ollis said fuel price should be accounted for but just needs a range while renewables are important on a short-term basis.

Ollis said staff do not have the data to get to 3000 runs but probably could get to between 600 to 900. Ollis then said running hydro years for adequacy is one thing but it's different from an economic perspective.

Heutte pointed to three recent hydro years that were well below average. He doubted that those three years were relatively identical, wondering how staff approached it. Ollis agreed that staff is trying to be careful about oversimplifying, talking about other complexities staff is facing.

Northwest Regional Loads in SCCP/OptGen

Heutte expressed curiosity about Economics being a Medium case in the Persistent high growth testing. Morrissey answered that the Medium case is still a robust Economic case. Heutte offered that for a high Economic case the Northwest would have to start looking like Texas all the time. Steve Simmons, NWPCC, answered yes.

LeVee asked how much of the load actions expressed on [Slide 12] include the price effect on customers. He clarified, asking if forecasting the peak and average of these different elements is at all based on changes in customer behavior due to price. Morrissey answered that not much is considered, explaining that hydrogen is elastic and will self-curtail on peak, while a lot of the forecasted growth, i.e. data centers, which run all the time and EV and electrification, which is following state policies are considered price insensitive.

LeVee stated that his work with DR committees show that there is a lot on the table that could change customer behavior due to pricing or storage. He called his perspective dynamic, asking if these dynamics could be included. Morrissey said they will be to some extent at the end of the 9th Plan. Morrissey explained that these forecasts are not capturing the impacts of DR or EE, but the capital expansion model can select those programs at different prices with the assumption that less expensive programs will be selected first, therefore capturing price sensitivity.

LeVee noted that Aurora can capture DR limits to consumption. He called this similar to hydro shaping wondering if that could be a path. Ollis agreed that that function is in Aurora, adding that there are other functionalities in the OptGen/SDDP portfolio that allow a look at DR and focus on the attributes with more structure.

Morrissey added that DR resources can be picked at different price points so the model can see the value to the system.

Heutte asked how staff is weighting the pathways on [Slide 13]. Morrissey said it is analyst judgement. Heutte said the real issue is uncertainty and not path unpredictability. Heutte explained further, saying up until recently we kind of knew what the future would look like, but we are now in a moment of technological transformation which will have many repercussions.

Heutte said there is a lot more uncertainty about the range of that new potential change, urging staff to look closely at that range and its implications for the resource portfolio.

Hansen confirmed that high growth was a combination of points 3 and 4 on the slide. Morrissey moved back to [Slide 8] to illustrate Persistent high growth. Hansen called those points reasonable.

Ollis said staff is comfortable with the range, but the question is do we believe all the factors will happen. Ollis said staff are not thinking about sampling these pathways evenly and want to know what committee members are strongly leaning towards in their individual work.

Heutte pointed to WestTEC work to set up a 20-year scenario assessment that leaned heavily on key drivers which include the overall state of the economy, technical innovation, and climate. Heutte said if economic growth is not that big of factor, the real factor is the other drivers. He suggested looking at these drivers.

Hansen asked how staff feel about the presented pathways, adding that he saw early growth as already happening and persistent high growth as likely. Hansen added that persistent low growth is unlikely.

Seelig said it's important to think about the loads we need to plan for because if we don't then we can't meet them. She asked where the biggest risk lies if we get it wrong.

Eric Graessley, BPA, asked for more information about the Mixed bag pathway. Morrissey explained the pathway. Graessley asked why this case has lower building electrification. Morrissey answered that some of the decarbonization goals might have been met through a different fuel, industry loss, etc.

Heutte stressed that he thought gas prices will play a significant role, pointing to LNG Canada and a report from Deloitte that predicts higher prices.

Ollis said staff is looking for guidance on how to wisely weight these pathways.

Heutte asked about residential heap pump replacements saying they do not fall under building electrification [Slide 16]. Morrissey said that should fall into the "Other RCI" bucket on [Slide 14]. Ollis said this is a new functionality brought by OptGen/SDDP and staff will try to implement this where appropriate.

LUNCH

Renewable Generation in the 9th Plan

Heutte asked if the chart on the right of [Slide 8] are in the 25-75% range. Dor Hirsh Bar Gai, NWPCC, confirmed. Heutte was surprised that any month could have 100% capacity factor across its entirety. Ollis explained that this is actually all 744 hours of the month.

Jason Sierman, ODOE, asked if staff ever see anything with higher capacity in the evening hours. Hirsh Bar Gai said he didn't look at evening hours and offered to follow up more offline. Sierman wondered if there were pockets of evening wind west wide. Ollis said that analysis hasn't been done but teased that must be a decent evening shape because the model liked wind.

Graessley asked if separate climate change data is randomly sampled on [Slide 9] or if there is some implied relationship. Hirsh Bar Gai answered that renewable availability and water years are all aligned for all 90 years.

Ollis thought the question was about offshore wind shapes. Graessley confirmed. Hirsh Bar Gai said he will have to check and get back to Graessley.

Morrissey explained the process used to align wind and temperature but was not sure if that happened for offshore wind. Hirsh Bar Gai said it does not. Graessley asked if there is data available saying he doesn't have any.

Heutte thought the data on [Slide 11] for Colorado looked low. Ollis said Colorado has great wind on the eastside but offered to look into it.

Graessley asked about Oklahoma. Hirsh Bar Gai moved to [Slide 10] to show that site.

Seelig suggested changing the name of South Center to South Central [Slide 14]. Hirsh Bar Gai apologized for the typo.

Heutte pointed to the wide dispersion of solar in central OR but thought it was okay to have an average. Hirsh Bar Gai said they were similar on a trend perspective. Heutte thought it might be different due to cloud cover and smoke. Hirsh Bar Gai said staff use PurpleAir data. Heutte spoke about seeing solar and demand being down during days of high smoke. Hirsh Bar Gai said that is high on Council list of things to investigate.

Heutte added to the converter ratios on [Slide 17] saying a solar/battery hybrid will change the equation adding that a lot of grid scape projects are coming in as hybrids. He thought 1.4 was okay for stand alone. Annika Roberts, NWPCC, added that rooftop solar is being treated more like an EE measure than a reference plant for the model.

Heutte said the rooftop resource is a lot better 100 miles east of the west side, but transmission constraints remain an issue. He called this a dilemma and was interested in the modeling results.

Nora Hawkins, WA Dept of Commerce, wrote Can you explain what "may use" 1.2 on the inverter ratio for rooftop? Are you using that as an assumption or is there flexibility? in the question pane. Roberts said there is an assumption, and staff will get back with more specifics.

Heutte pointed to two reasons to look at the information on [Slide 18], constrained transmission which a hybrid approach can optimize, and system need. He said there is a lot of available data from CA and TX about these hybrids.

Modeling Hydrogen Load in Council Models

Devin Gaby, CES Ltd, mentioned his work over the past few months with the Renewable Hydrogen Alliance saying he was glad to see this included. Gaby called the 70% factor a good goal target while the price of electricity is the driver of electrolyzer profitability. Gaby thought the curtailment price may be lower than $150 and closer to $100.

Morrissey thought they could start at $100 or $125. Gaby called the shift from alkaline water electrolizers to proton exchange membrane electrolyzers big because they are much more flexible. Morrissey asked how hard electrolizers can ramp. Gaby said manufacturers claim they can ramp within the hour, with minimum levels.

Essenberg assumed that there would be a tacit assumption that the price of hydrogen will be high enough to make money at high electricity prices. Morrissey said yes, to some extent, referencing decarbonation policy in OR and WA. He added that prices over $100-150 will present a modeling problem.

Essenberg thought an alternative could be if prices are that high the plants are not economical so the other builds wouldn't happen because there is no load. Morrissey agreed, saying the assumption is the price would be below $100.

Ollis added that there a cap on volatility that is probably interacting with the hydrogen investment.

Market Availability Study: Preliminary Results and Implication

Sierman wondered if preference customers were part of the limitations on flexibility [Slide 5]. Ollis said that could be for BPA. Graessley said it has nothing to do with loads but with constraints on the hydro system.

Sierman said the hydro system is bigger than the preference customers' contracts. He wondered if the flexibility is about what is not dedicated to those customers. Ollis said it is but reminded him it is not the only factor limiting the hydro system.

Sierman then said the transmission limitations (hurdle rates) might change in a more unified market. Ollis agreed, saying he did not have the current market split out available.

Joel Nightingale, WA UTC, wrote can you say more about the dependency/correlation between renewables generation assumptions and the hydro year? Is this only for the purposes of the AURORA setup (regional electricity costs), or is this the case for the NW resource build as well? (Apologies if I missed something earlier!) in the question pane. Ollis said it is the case for both.

LeVee offered that he has run it both ways, saying individual entities with contracts look at cost minimization have two perspectives: dedicating those resources to your loads and getting that at a lower price or satisfying all loads based on market prices. He said netting the two together you come back to the same overall power costs.

Hansen called the draft proposal on [Slide 7] just fine, commenting that there has been a recent shift. He noted the 17,000 MW of new wind and 50GW of solar but noticed that the SCCT and

CCCT are limited to 10GW. Hansen said these numbers are not binding numbers but noted that a lot of utilities are adding gas. Ollis said he is happy to raise those numbers.

Clement was curious if the reserve margin will still be limited. Ollis agreed that the reserve margin might be a bit too heavy handed and said that can be explored.

LeVee said when looking at planning reserve margins, risk analysis, etc., energy becomes the only real commodity [Slide 9]. He said thinking of capacity as separate from energy is a misnomer. LeVee said the capacity margins correlate to incorporating the full range of potential outcomes.

Ollis said he and the Council agree, saying it makes regional analysis robust, but he can't get it done in Aurora.

Heutte noted that PGE has 500MW of batteries online today [Slide 11]. Ollis said the existing numbers are in there.

Heutte thought that it was 1500MW on the B2H [Slide 12]. Ollis wasn't sure. Heutte explained the allotments. Ollis said he was happy to change the assumptions on B2H.

Karpoff thought the CCA estimate on [Slide 14] is substantially lower than what she sees, even at mid-CCA scenario. She expressed curiosity about where staff got their numbers. Ollis thought the CCA was linked to CA as a proxy and might have an error. Karpoff offered a link to her numbers.

Heutte expressed disappointment that he didn't catch this, saying current CA prices are high $20s per ton. Ollis said the slide is dollar per MWh. Heutte asked for a conversion. Morrissey said three. Heutte said that means it lines up, calling WA a special case for now.

Heutte asked about the long-duration storage technology represented on [Slide 15]. Ollis answered Iron Air Battery. Heutte wondered what that technology could actually do. Ollis said that's coming up.

Heutte thought the long duration market will be competitive [Slide 20] saying curtailment is an economic signal. Ollis thought upping the limit a little in later years might be a good solution. Heutte thought that Form will do more as will other technologies.

Sierman asked what the model likes about long duration storage. Ollis said the model gets rid of the negatively priced energy and dispatches for peaks. Ollis called the Aurora modeling imperfect here and was looking forward to seeing what OptGen/SDDP does.

Sierman asked if long duration operators would hold on to or release energy. Ollis said he's heard people say they would hold on. Hanson said it's hard to nickel and dime daily differences with long duration storage due to low round trip efficiency. Hanson said the shifts are more seasonal than daily.

Frank Brown, BPA, wrote Were new NG plants and SMR's available for selection? in the question pane. Ollis answered yes, pointing to new natural gas on the chart.

Sierman asked how many data points were used for the cost projections. Ollis said emerging tech will be available later or at higher costs as a way to mitigate their risk.

Heutte said CA is dispatching 10,000 peak hours today with several more coming [Slide 22] so they could have what they want. Ollis agreed this seems like an artificial constraint.

Graessley wondered about the timing of natural gas saying staff is showing modest amounts [Slide 20]. He wondered how quickly you could see a new natural gas plant as BPA tends to delay availability, adding that he didn't feel good about that tactic.

Heutte said if you have a place in line with one of the manufacturers you could get it at a price and if you're not in line you have to wait until 2031. He added that those in line have to pay reservation costs. Ollis called that interesting and was happy to slow the gas build.

Heutte said the big manufacturers can ramp up operations but are being cautious about new orders.

Heutte then moved to geothermal, saying a new Fervo plant will be sending energy to at $79 per MWh. Ollis said that sounded pretty sweet.

Ollis ended the meeting at 3:45.

Attendees via Zoom Webinar

Jennifer Light	NWPCC
Tomás Morrissey	NWPCC
John Ollis	NWPCC
Steven Simmons	NWPCC
Dor Hirsh Bar Gai	NWPCC
Daniel Hua	NWPCC
Jake Kennedy	NWPCC
Annika Roberts	NWPCC
Peter Jensen	NWPCC
Fred Heutte	NW Energy Coalition
Aliza Seelig	PNUCC
Carla Essenberg	BPA
Jared Hansen	Idaho Power
Eric Graessley	BPA
Alan Bach	Seattle City Light
Paul Barrager	WA UTC
Ryan Bottem	Public Gen Pool
Frank Brown	BPA
Pat Byrne	BPA
Erin Childs	Renewable H2
David Clement	NEEA
John Crider	EWEB
Joaquim Dias Garcia	PSR INC
Christian Douglass	NWPCC
John Edgerly	Seattle City Light
Katie Ewing	Seattle City Light
Devin Gaby	CES, Ltd
Nora Hawkins	WA Dept of Com
Lori Hermanson	Avista Corp
Alexandra Karpoff	PSE
Rebecca Klein	Seattle City Light
Mary Kulas	Consultant for PPC
Dave LeVee	Pwrcast
John Lyons	Avista
Ian McGetrick	Idaho Power
Devin Mounts	PGE
Agusto Navarro	Kcha
Joel Nightingale	WA UTC
Elizabeth Osborne	NWPCC
Craig Patterson	independent
Shannon Pressler	WA Dept of Commerce
Blake Scherer	Benton PUD
Jason Sierman	ODOE
Alessandro Soares	PSR Inc

Shannon Souza	Obsidian Renewables	Ben Ulrich	EWEB
Mike Swirsky	Critfc		