Minutes for Demand Response Committee
May 30, 2025

Joe Walderman, NWPCC, began the meeting at 1:30pm. Kevin Smit, NWPCC, called roll.

Nicolas Garcia, WPUDA, confirmed that the $28 levelized cost was for both existing and new thermostats [Slide 6]. Walderman replied yes, adding that they are weighted based on the 70/350MW of potential.

Garica suggested separating them as the 70MW of existing thermostats would have a much lower cost per kWy versus the new thermostats. Walderman called that a fair point and might be a good approach to take.

Tom Eckhart, UCONS, wrote: How will charging new WA state electric ferry batteries (during peak demand hours) be accounted for? in the question pane. Smit wrote: Well, if it gets into our load forecast then it will be accounted for. I don't believe we will have a separate DR product for this.

Jeff Harris, NEEA, questioned $170 for thermostat cost, wondering if that represented the incremental cost needed to add connectivity above and beyond the equipment cost. He then asked how staff will parse out the cost of the energy efficiency value of a smart thermostat versus a demand response value of a smart thermostat.

Walderman addressed the second question, saying there is no efficiency measure for residential smart thermostats in this Plan. For the first question, Walderman answered that people buying their own equipment is part of the BYO Thermostat DR program and is reflected by a modest growth rate. Walderman thought the incremental cost of connectivity versus an unconnected thermostat was an interesting concept.

Harris then said that he thought that Energy Trust of Oregon has a smart thermostat efficiency measure. Smit was not sure and offered to find out.

Laura Tomas, NWPCC, stated that the RTF is looking at this because evaluations are showing no savings for electric resistance homes. Harris recalled differences between equipment choices and the confounding issues between HP, electric, and gas furnaces. Tomas said the RTF will be looking at this in September, but preliminary evaluations are showing no electric savings.

Cam LeHouillier, Tacoma Power, asked if the 1.7% annual adoption rate was primarily new construction or if it assumes utility programs. He then asked if the forecast considers if and when smart thermostats might make it into codes and standards. Walderman was not sure if the 1.7% has specific considerations around new construction and offered to find out more.

Smit addressed codes and standards saying it has to be on the books to be considered. LeHouillier asked if there is any assumption around utility incentives that feed into the 1.7% number or if it's straight-line growth. Walderman answered that it is straight-line growth.

Mark Jerome, CLEAResult, wrote: Unlikely to have Smart Thermostats in new construction codes due to the fact that most Smart Thermostats use 24-volt control and HVAC equipment that are high efficiency do not use a 24-volt control. They are proprietary and use a different communication protocol, in the question pane.

Fred Heutte, NW Energy Coalition, asked about the 20 to 1 split between the electric resistance water heater and the HPWH [Slide 7]. He said there will be 1.5 full replacements of water heaters over the 20-year Plan meaning that a lot of electric resistance will be replaced with electric resistance, despite the advantages and advances of HPWHs. Heutte wondered if the outcome is driven by levelized cost or something else in the mix.

Walderman reported that Council forecast around saturations doesn't change a lot through the Plan's timeline but does allow for some EE adoption. Smit agreed that there is a basic stock turnover to current practice which is a mix of resistance and HP. Smit then touched on a federal standard that may or may not come into play.

Heutte asked about the water heating market space, including gas to electric conversions. Heutte thought making that change is easy and wondered if 120 volt plug ins are included. Walderman answered no, as that equipment is not included in the Council's existing stock forecast, but it could show up in emerging technologies.

Heutte noted that the CRAC talked about emerging tech in their meeting. He said CTA 2045 technology is in the OR and WA market now, calling it a huge opportunity regardless of the achievable potential, and might show up in the next decade. He hoped the Council will lean heavily on this technology calling it an important resource to develop.

Harris agreed with Heutte, adding that all electric water heaters in OR and WA must be CTA 2045 compatible by the end of the 20-year Plan. Harris then addressed information from the CRAC that revealed that HPWH will not proceed because of 2029 federal standard issues.

Harris said if the standard does take effect, it would mean that 80% will be HPWH. Harris understood that staff cannot count on that but urged writing documentation that says if the standard does take effect, it will drive adoption in all four states.

Harris then pointed to the BPA/PGE/NEEA study on CTA 2045 showing that electric resistance and HPWH both had demand response results on a diversified basis. He reported that electric resistance offered over 500W while the HPWH offered over 200W. Harris thought a major saturation of connected HPWH should have a potential over 20MW. Walderman confirmed that

Harris was referring to the 2018 report, wondering if there were stock assumptions. Harris said he was talking about watts per unit, reiterating that it is half for HPWH versus electric resistance.

Harris said no federal standard will result in a bigger number while a federal standard will result in half the technical potential because the HPWH diversifies load. Walderman said those assumptions are incorporated.

Harris then asked if the DR benefits are at the bulk power system level and not the distribution/feeder level. Walderman answered yes. Harris said that hybrid HPWHs still have an electric resistance element and is less diversified on a feeder than a bulk power level. Harris said it's a different value calculation than the bulk power system. Walderman called this interesting.

Heutte wrote: adding to Jeff's comment, while HPWH has lower peak reduction per unit than ERWH, that's because the EE characteristics of HPWH reduce the need for on peak heating considerably and that should be fully accounted for in the assessment of EE peak value in the question pane.

LeHouillier asked for details about the assumed grid modules cost as he would like to compare the numbers with internal estimates. Walderman said that will be challenging as costs vary by bulk order and across the timeline of the Plan. Walderman said staff landed on $110 per port and $10-$15 for annual fees. LeHouillier said this was similar to his numbers but offered to check.

Garcia wondered if there is any information about increase/decrease of actual usage (a conservation effect) if you move heating times [Slide 8]. Walderman said the idea is that customers do not experience any cold showers as the equipment is preheating. Walderman said the event participation rate assumes if there were no hot water customers would opt out, but that ideally would not happen.

Harris appreciated staff treating water heaters as a frequent resource but thought that yields might be different on a diversified basis depending on condition, season, and time of day. Harris thought there might be morning hour market benefits with high prices and a system model that operates on an 8760-market price purchase avoided cost. Harris encouraged staff to think about making a full 24/7 dispatch available using a monthly profile with less morning dispatch.

Walderman said that is the idea and this slide is just an example. He spoke about some difficulties but called this an interesting thought.

LeHouillier addressed the 40% assumption of cars signed up for programs, asking if there is a subset of cars enrolled in programs where the charge can be managed [Slide 9]. He pointed to data that showed that only 30% of enrolled cars are below the desired state of charge or are currently plugged in. Walderman said the potential on the slide takes that into account, saying staff used 20% with a 50% throttle. He said they use the load shape of EV charging forecast to develop DR potential.

Harris asked if staff looked at actual vehicle to grid energy dispatch. Walderman said staff discussed it but didn't have data or commercial availability. Harris said the promise is there and it could be huge. Harris suggested this make it into the emerging technology DR section of the Plan.

LeHouillier asked about managed charging for medium and heavy-duty vehicles. Walderman answered no but said there could be space for it. Walderman said they haven't found peak coincident charging with this class of vehicle. LeHouillier agreed this was an area of high uncertainty, particularly with the EPA waiver under threat. LeHouillier continued, saying that if there is no program for this class of vehicle, owners will plug in at the end of a shift, around 5-6:00pm over the evening peak.

Jennifer Finnigan, Seattle City Light, approved of including the $500,000 to partly cover billing and needed IT for setting up price-based DR [Slide 11]. She pointed to participating in NEEA's end use flexibility group, asking how that $500,000 applies to large versus small utilities adding that SCL just received their DR Potential Assessment results.

Walderman said he would like to see those results. He continued, saying the $500,000 is the middle ground as individual utility costs vary widely.

Finnigan stated that critical peak pricing comes up in every DR PA they do, so she was curious about how that number would change things. Walderman previewed that it will probably not change things much as set up costs are not much of a driver of costs over a 20-year period.

Harris asked if the cost is an increment to the existing, enterprise-level billing/metering system or a stand-alone cost of implementation. Walderman agreed this is difficult as adopting for one DR program means that it is borne for all that come after. Walderman said staff tried to look at each DR program on its own. Walderman added that staff understood and tried to acknowledge that some utilities already have the infrastructure while others are building.

Aquila Velonis , Cadmus Group, asked if the $500,00 is split evenly across the three. Walderman said the cost is attributed to each, including the normal set up costs that come with any DR program. Velonis confirmed that it is $500,000 for each of the groups. Walderman said yes.

Leona Haley, Avista Corp, wrote: Pricing programs require configuration changes to the billing system and meter data management system, bill updates, web enrollment work, testing, and more testing, in the question pane.

Garcia asked how the numbers on [Slide 16] compares with the last Plan. Walderman revealed that the last Plan had 3600MW including irrigation. Walderman added that irrigation was removed this time.

Heutte said [Slide 17] shows a large amount of fairly cheap available DR, which is better than the last Plan. Heutte added that gas peaker prices are going up by 100% through the early 2030s making it $200-300 a KW year for batteries or a conventional gas peaker. He said most everything on the slide is less than that and most is much less.

Heutte pointed to categories with large resource potential saying it's obvious where we need to concentrate the effort. He hoped the Council will push hard to move the region on this.

Garcia agreed with Heutte but cautioned that there will have to be a fundamental change for that to happen, particularly with the utilities he works with. Garica said they are BPA full-requirement customers and don't get a price signal unless BPA announces it. Garcia thought the Council should emphasize this in the Plan to jump start a DR program.

Garica asked if achievable means the technology is available but doesn't account for utilities that don't have the signal to implement a DR action. Walderman said yes, it's a matter of eligibility, stock, and ramp rates.

Finnigan was stuck on set up costs reflecting all utilities. She saw achievable potential for critical peak, time-of-use, and real-time pricing but said wondered how the $500,000 set up costs would work. Walderman said the analysis is regional with some exploration into the locational value of DR and it gets fuzzy with specific utility costs. He asked Finnigan for some clarity.

Finnigan pointed to industrial critical peak pricing for example. She interpreted that to mean a number of utilities should offer the program as it is relatively inexpensive. Finnigan continued saying those utilities could be big or small as customer location is what matters. Finnigan was not sure if a large customer located in a small utility's service territory would be willing to pay a $500,000 set up cost.

Walderman said staff has to choose one value and that is why the potential is so low.

Harris wrote: Where can we find the detailed input assumptions for each of the resources? in the question pane. Smit responded It should be on our web site and also presented in the past DRAC meeting. I will double check where these are posted.

Velonis asked about the value of set up costs wondering if it was per utility. He also wondered if the potential is a regional value or if the $500,000 is the regional value of the set-up cost. Walderman agreed it is tricky, explaining it's a cost staff model for a given DR program and divided by zone.

Velonis confirmed that the shown levelized cost is the average across the zones. Walderman said it's the total based on regional potential. He recognized the set-up cost concept is difficult and asked if the DRAC wants a different approach.

Velonis confirmed that there is no T&D deferral in these values and if they were added there might be negative levelized costs in some categories. Walderman said staff is working on an approach on how to include those costs as system peak times don't always line up with distribution/transmission peak.

Heutte argued strongly that the region cannot sell DR short in the 9th Plan, pointing to past stressful weather events. He said DR takes a while to develop and the region cannot wait for another weather event where there is a possible loss of load. Heutte said if Bonneville is not willing to shift their approach to motivate their customers the IOUs and big loads like data centers might take more of an interest.

Garica spoke about event-based dispatch [Slide 21] saying staff has to pick a count that reflects that these technologies will not be available for BPA's full requirement customers. He suggested netting them out of the system until BPA makes some changes.

Smit said staff did a potential assessment and if there is a need for a program BPA and the utilities will develop it. He said staff will put the potential out there and put recommendations and responses in the Plan.

Walderman talked about next steps before ending the meeting at 3:00.

Attendees via Zoom Webinar

Kevin Smit	NWPCC
Laura Thomas	NWPCC
Joe Walderman	NWPCC
Barry Richardson	NWPCC
Tomás Morrissey	NWPCC
Nick Gemperle	PSE
Suzanne Frew	Snohomish PUD
Aquila Velonis	Cadmus Group
Robin Maslowski	Trillium Energy
John Purvis	Clallam PUD
Jennifer Snyder	WA UTC
Paul Koenig	WA UTC
Mary Kulas	Consultant PPC
Heather Nicholson	Orcas Power & Light
Jeff Harris	NEEA
Brian Dekiep	NWPCC
Zeecha Van Hoose	Clark PUD
Mark Jerome	CLEAResult
Tom Eckhart	UCONS
Aaron James	NEEA
Todd Myers	WA Policy Org
Leona Haley	Avista Corp
Laura James	PacifiCorp
Cam LeHouillier	Tacoma Power
Fred Heutte	NW Energy Coalition
Rob Del Mar	ODOE
Nicolas Garcia	WPUDA
Nolan Kelly	BPA
Bonnie Watson	BPA
Gordon Gimse	WA UTC
Scott Reed	PPC
Jennifer Finnigan	Seattle City Light
Nora Hawkins	WA Dept of Commerce
Brittainy Pond	PSE
Shailesh Shere	Clallam PUD
Bryce Yonker	Grid Forward
Brenda Hunt	NEEA