Northwest Power and Conservation Council
Demand Response Advisory Committee
February 20, 2025

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

9th Plan DR Costs

Nicholas Garcia, WPUDA, saw a challenge with establishing costs for utilities without AMI [Slide 10]. Garcia asked for more information on this. Walderman said this will be discussed later, but previewed that staff consider this a regional proxy for DR and AMI has benefits across the system. Walderman said AMI is considered for DR potential but is not included in the cost of DR products. Garcia was concerned by this answer as it assumes a reduced level of cost per utility and looked forward to future discussion.

Ted Light, Lighthouse Energy, asked if the T&D costs on [Slide 11] have been updated. Walderman answered yes. Smit confirmed that they were adjusted after a utility error. T. Light asked for a link to the updated math. Jennifer Light, NWPCC, said they will be posted.

Brenda Hunt, NEEA, asked about including Value of Service Lost [Slide 13] as the incentive overcomes customer inconvenience. Hunt thought this felt like a double penalty. Walderman said Value of Lost Service will be used as a percentage of the total cost of the incentives not applied. J. Light added that this was the methodology for the 2021 Power Plan and not necessarily for the 9th Plan.

Peter Kernan, OR PUC, said that his organization has been guiding utilities to not include the Value of Service Lost partially because of Hunt's comment. Kernan said other drivers for this decision include the fact that some historic values seem arbitrary at times. Kernan said that he is not against this as a concept, but evaluation work should quantify the percentages.

Smit clarified that OR PUC requires incentives to be included as a cost but not the Value of Service Lost in the TRC test. Kernan said in they cancel out in the TRC but are present in the UTC.

Rich Arneson, Tacoma Power, asked for a description of how a DR incentive payment is a transfer payment [Slide 14]. Walderman said it is money moved within the region

John Ollis, NWPCC, added that it is an incentive cost from a wholesale electricity provider to a customer. Arneson said he understand the concept when buying a conservation measure but in DR most of the incentive is to compensate the customer for loss.

Ollis said this an ongoing internal and external conversation. Ollis is open to refinement, saying DR is unique as the incentive is part of what makes it possible. Ollis said that some

DR is designed for the customer to not notice while other DR is noticed. Smit said staff are wrestling with this and plan to come back with more clarity about the approach.

Robin Maslowski, Trillium Energy, shared that the transfer of the incentive payment is a byproduct of the TRC test, explaining how it is done in CA.

Garcia pointed out that DR for EVs is challenging as sometimes the user wants the vehicle charged when they need it so they will override the program as opposed to other times when it doesn't matter to the customer. Garcia then brought up seasonality issues with getting industrial customers involved in a DR program. Garcia said this time component is linked to the cost of participation and staff should think about this.

Brittainy Pond, PSE, thought the $150,000 on [Slide 15] made sense. Pond asked for clarity around "each program" asking if product and program are synonymous. Walderman answered that they are synonymous. Pond said they the $150,000 resonates.

Jennifer Finnigan, Seattle City Light, said that implementors do not like this. Finnigan struggled with the $150,000 applying to all utilities, programs, and sizes. Finnigan then addressed a large customer curtailment program, saying the set-up costs are different than a bring-your-own-thermostat program. Finnigan wished the number was based in data and not just judgment and would like to collect and talk about data.

Walderman said staff is struggling to come up with a regional number too adding that this could be included in a narrative.

Finnigan liked the idea of providing text and guidance about applying these assumptions. Finnigan says taking Plan assumptions for EE works, but one size does not fit all for DR. Smit added that staff want to hear about higher/lower costs, saying the presented data comes from stakeholders.

T. Light thought that these costs vary both between products and within vendors of a single product. T. Light said that for bigger utilities or even region-wide the variable cost is usually a bigger driver. T. Light encouraged the DRAC to accept some uncertainty here as $150,000 over a 20-year program is a small portion of the cost.

Walderman said staff do not have a way to incorporate both fixed and variable O&M costs, so putting some of the fixed cost into a higher set-up cost could be a better representation.

T. Light clarified that quotes have a variety of fixed and O&M costs and suggested putting fixed costs in a one-time set up bin and the variable costs in another.

Jennifer Snyder, WA UTC, wrote: An incentive would be a cost to the utility but a benefit to the customer, so in a TRC those cancel each other out. Correct? In the question pane. J. Light wrote Yes.

Angela Long, Rock Cress Consulting, recalled discussion around set up costs, agreeing that they vary significantly. Long said the size of the utility matters and software is not scaled for small utilities. Long added software features matter as well, which can influence whether a utility can buy something off the shelf or will need to buy a custom product.

Frank Brown, BPA, called this a tough issue to deal with, saying it's variable. Brown recalled running a five to 10MW irrigation program for two utilities with zero set up costs because they had software in place. Brown said other small, yet complicated, DR pilots required one FTE employee for a year.

Brown said this cost goes in the first year as part of stream of annual costs and has a small effect on the levelized cost. Brown stated that the annual repetitive costs matter more. Because of this Brown felt you could put in any number, and it wouldn't have much impact.

Garcia pointed to an earlier comment about the size of a utility mattering, saying it is true. Garcia then asked how this information will be presented in the final Plan, arguing that the recognition of different utility costs/benefits should be presented. J. Light said this is not the first time she has heard this suggestion now that the model offers more granularity. J. Light said the Council will think on these questions, saying there will be at minimum a regional Power Plan and recommendation to BPA, but she expects the variable value of resources will be discussed as data comes in.

Garcia added that it would be helpful to do an analysis for a large and small utility, as some PUDs have 1000 or fewer customers. Garcia said this really affects costs.

Andrew Grant , Cadmus, asked if the presentation is in 2016 or 2024 dollars. Smit said the Ninth Plan will be in 2024 dollars, but this slide is 2016 dollars.

Hayden Reeve, PNNL, asked about the 10, three-to-four-hour event assumption for direct load control [Slide 18], saying that works for heating/cooling but was curious about managed EV charging. Walderman said he wants to discuss this further, pointing to an EV time-of-use rate that will be discussed at a future meeting.

Walderman continued, saying he has heard that active charging is harder to do with a year-round everyday setting and was open to suggestions.

Arneson moved back to the 10, three-to-four-hour events, wondering about the shape of the peak. Arneson said a short duration, needle peak would work well, but a longer, four-to-five-hour peak would require feathering in and out multiple tranches of DR for management.

Walderman thought that could work in practice but might be hard to fit into the model. Walderman said it's hard to do this in an event-by-event basis and this is more representative of the most common needs and characteristics.

Ollis agreed that there are model limitations but said there could be more flexibility if the DRAC deems it necessary. Ollis added that it is hard to identify exact needs, especially over a 20-year planning horizon.

Brown stated that BPA doesn't need a three-to-four-hour product as a five-to-six-hour event delivers the best value. Brown said you can cycle loads to get to those five-to-six-hour events. Brown asked if the bullet represents a curtailment or cycling strategies.

Walderman said this is based on programs that are deployed today, like a thermostat program. Walderman said staff can explore other strategies like AC cycling.

T. Light addressed the EV question, proposing two EV products. T. Light said one could be limited events while the other is more reflective of a TOU/daily product, admitting this would split the participant pool. Walderman said staff could explore this.

Reeve wrote: Not really a question, more a comment: EV managed charging (through TOU for example) and DLC of EVs need not be mutually exclusive as well in the question pane.

BREAK

Finnigan said she assumes $16 for O&M [Slide 23]. Walderman thanked her.

Josh Rushton, Rushton Analytics, noted the three DR event modes found in the CTA 2045 documents: shed, critical peak event, and grid emergency. Rushton wondered if these programs are shed events or something else. Walderman said right now the assumption is water heating will be frequently (daily) deployed but other DR products, like thermostats, are on more of a 10-20 times a year schedule.

Hunt wrote: Are you accounting T-stat OEM annual fees (usually pass through DERMs provider) in the question pane. Walderman said this is the trouble of looking at O&M costs. He asked Finnigan if the $16 she referenced included the O&Ms. Finnigan asked for a minute to look.

Arlen Korteland, BC Hydro, wrote: Do I get it right that cost to acquire is $35+$50 = $85 per participant, of which $50 is enrollment bonus? And: is $35 marketing cost sufficient? Walderman asked the group for input, saying the $50 is a standard marketing cost but Puget Sound Energy's numbers are coming out closer to $35.

T. Light thought the numbers looked reasonable. T. Light asked Walderman if he was aware of a LBNL report that had data on response and rates, offering to send it along.

Finnigan responded to the earlier discussion around $16 O&M, saying she will forward the information she has.

Korteland wrote: To clarify question: target of recruiting 1,000 households would cost $35K marketing cost all-in, which seems limited for marketing campaign in the question pane. J. Light asked for DRAC feedback on this.

Finnigan said SCL was significantly lower, around $16 for marketing costs, adding that her utility is different.

T. Light cautioned to keep a wholistic view on different costs and not focus in on individual costs as some vendors have higher upfront costs while others keep them low.

Finnigan wrote: SCL results: 0.25 for Winter; 0.26 for Summer and Program participation: 20%; event participation Summer 77.7%; Winter 80.6%in the question pane [Slide 24]. Walderman asked if this was lower than expected and the heating type. Finnigan responded yes it was lower, and existing heating was a question for them. She offered to forward the report.

Korteland asked What is included in the marketing cost / how is marketing cost defined in this table? In the question pane. Walderman answered it's a proxy of customer acquisition costs, i.e. outreach, advertising, communications etc.

Leona Haley, Avista Corp, wrote: Are these impact values an average across all the hours per event, ie…1.0 kW per participant for the entire event? Haley wondered if these are all the values across the event or just per participant. Haley asked if 1KW gets 3-4hWh.

Walderman said this is the assumption, admitting that in reality most savings would be seen in the first hour before customers start overriding. Walderman said the numbers are the average across all hours. He pointed to an opportunity to focus on max impact which could use the load shape for scaling.

Laura James, PacifiCorp, wrote: For Summer 2024, for Pac Power, we were seeing ~0.7 kw reduction among non-opt out participants, preliminary analysis in the question pane. James added that they launched a program this year with a 1,000 customers.

Walderman thought this feedback warranted shifting the numbers down, asking for more data points.

Pond added that PSE evaluations were on two pilot areas that are trending down, with data that will be available soon. Pond said the numbers are in-line or lower than the shown numbers, but PSE is going system wide with different housing types and populations.

Aquila Velonis, Cadmus Group, asked if event participation values account for competition with other products. Walderman thought so, saying this slide shows 25-35% participation but cool switch [Slide 26] is 10% while heat switch has 25%.

Haley thought participation rate would vary across zone as comfort is the difference between indoor/outdoor temperature. Haley said they saw more overrides when calling events on the east side, wondering what west side utilities saw.

Walderman pointed to the ability to create values for zones, cautioning that they would not do that for all 17 but would differentiate between east and west. Walderman asked if 25% makes more sense for the east relative to 35% for the west. Haley said that was okay in the absence of real data.

T. Light did not know of many programs using Cool Switch [Slide 26] wondering if more focus should be put on smart thermostats. Walderman said Cool Switch is still active in Idaho Power and perhaps PacifiCorp but was not aware of any Heat Switch programs.

Quentin Nesbitt, Idaho Power, reported that they still have their switch program, but it is decreasing in size. Nesbitt revealed that PacifiCorp prefers a switch program to a bring-your-own thermostat program and are planning to expand into Oregon. Nesbitt said the switch program is cheaper even though Idaho Power is starting a bring-your-own-thermostat program.

James said Rocky Mountain Power is growing that program as their customer base is growing in the Salt Lake City area. James said it will be expanded into OR/WA with significant capacity. James said this will not be used for peak shaving, wondering how relevant that is for Council modeling.

Brown wrote: I have observed over the decades that you can get higher program participation (65%-85%) in coops and small municipal utilities than in large muni's and IOUs. It all depends on the messaging. Public utility consumers can feel like they have a real ownership stake in their local utility and be persuaded to take action for the good of their utility resulting in high participation rates - even without any incentives. in the question pane.

Tom Eckhart, UCONS, asked if there is any differentiation between zonal and whole house heating systems. Walderman said not at the moment as the goal is coming up with program averages. Walderman asked if the numbers looked high. Eckhart noted a zonal, mini split pilot for Tacoma Power and King County. Eckhart hoped the potential applications would look at zonal applications as well as whole house.

Smit referenced a similar question from Korteland in the question pane: is it per household? Do proposed assumptions change when multiple baseboard thermostats in single household? Smit said this can be considered. Eckhart was hopeful the 9th Power Plan would make the differentiation between zonal and whole house. Walderman said this could be discussed.

T. Light wrote: I think smart thermostats and switch programs would necessitate a central systems, not zonal, in the question pane.

Ollis added that the capital expansion model understands reserves better so if DR is used for contingency reserves, it can be reflected in the model.

James said the numbers on [Slide 28] look significantly higher than their expectations.

Nesbitt said they had to buy equipment in volume to bring the cost closer to $200, adding that it doesn’t include install costs of $150-180 per site.

James reported that their switches cost $140 to $160 and guessed the labor costs were $100.

Haley wrote: Doesn't WA state require this work (switch install) be done by an electrician and permitted, in the question pane. Nesbitt said Idaho doesn’t require that for AC cycling. James said Utah doesn’t as well and they are still working out what to do in OR.

Arneson confirmed that $230 was for an installed, hardwired switch, saying it sounded low. Nesbitt commented that they are not doing heat switches and installers are not electricians but HVAC techs.

Smit asked if WA requires an electrician. Arneson pointed to a past water heater control switch program that had a blanket inspection fee to simplify costs. Arneson was not sure if that was still the case. Smit said the costs appear to be closer to $300 or higher.

James recalled short-lived water heater program that cost $100 a unit. James thought NEEA might have some more information. Arneson wrote: Joe, I will follow up with you on Tacoma installation costs from the pilot water heater DR program.

Haley wrote, I will call the local inspector's office to get clarification and let you know what I find out. Thank you!

T. Light thought a grid connected water heater could do a little better [Slide 31] but had not seen data. Walderman agreed, saying it’s closer to an event participation rate decrement as you would see more overrides. Walderman thought he would bring it down to 85%.

James said the switches she was going to use were capable of preheating and performing various ramp up/ramp down patterns. She wondered why anyone would assume a switch couldn’t perform like a grid-connected module.

Walderman said the assumption for just an on/off load switch.

Haley wrote Based on a small pilot Avista ran (50 customers) in ID w/switches, we saw about .3-.35 kW per event. All single-family homes, in the question pane.

Brown wrote: There are water heater switches that can switch on and off every 20 Hz, three times a second, in the question pane.

Haley said she pays a company to help with managed EV charging and they charge between $20,000 to 35,000 a year with a $35-40 per participant fee [Slide 39]. Hailey expects this to go down as participation grows. Walderman confirmed this is one O&M. Haley said yes, speaking about the features like an app.

Walderman asked how long they have been running the program. Haley answered 18 months offering to talk more offline.

Nesbitt thought the $10 is low for managed charging, which is why it is not cost effective for Idaho Power. Walderman said the number may need to jump up and offered to reach out.

Walderman ended the meeting at 4:30.

Attendees via Zoom Webinar

Kevin Smit	NWPCC	Sophia Spencer	Nauvoo Solutions
Jennifer Light	NWPCC	Rian Dekiep	NWPCC
Joe Walderman	NWPCC	Ahlmahz Negahs	Tacoma Power
Laura Thomas	NWPCC	Tom Eckhart	UCONS
Suzanne Frew	NWPCC	Mark Jerome	CLEAResult
Leona Haley	Avista Corp	Jennifer Snyder	WA UTC
Ted Light	Lighthouse Energy	Zeecha Van Hoose	Clark PUD
Robin Maslowski	Trillium energy	Elizabeth Osborne	NWPCC
Talia Mirel	WA Dept of Commerce	Fred Heutte	NW Energy Coalition
Malcolm Ainspan	NRG	Shivani Subramaniam	WA Dept of Commerce
Hayden Reeve	PNNL	Scott Reeves	Energy Futures
Blake Scherer	Benton PUD	Eli Morris	Applied Energy Group
Frank Brown	BPA	Laura James	Pacificorp
Brittainy Pond	PSE	Tom McCarroll	Tacoma Power
Paul Koenig	WA UTC	Nora Hawkins	WA Dept of Commerce
Brenda Hunt	NEEA	Rob Del Mar	ODOE
Nick Sayen	OR PUC	Jennifer Finnigan	Seattle City Light
Angela Long	Rock Cress Consulting	Aquila Velonis	Cadmus Group
Kyle Billeci	PGE	Peter Kernan	OR PUC
Kari Montrichard	BC Hydro	Nicolas Garcia	WPUDA
Arien Korteland	BC Hydro	Andrew Grant	Cadmus
Landon Snyder	Snohomish PUD	Rich Arneson	Tacoma Power
Aaron James	NEEA	Josh Rushton	Rushton Analytics
Sonali Razdan	DOE	Quentin Nesbitt	Idaho Power
Brien Sipe	PGE	Juan Carlos Blacker	PGE
Mary Kulas	consultant		