**Northwest Power and Conservation Council**
**Demand Response Advisory Committee**
**June 4, 2019**

Tina Jayaweera, NWPCC, began the meeting at 9:30 am with introductions. She reminded DRAC members about the last RTF DR subcommittee meeting.

**Levelized Cost for Demand Response**
**Tina Jayaweera, NWPCC**
Nicolas Garcia, WPUDA, asked about replacing worn equipment versus buying new equipment for expansion [Slide 6.] Jayaweera acknowledged that a lot of T&D may be O&M, adding that tracking is inconsistent between utilities. She said she uses a proxy value of the portion that is O&M based on WA UTC work.

Lee Hall, BPA, pointed to two buckets of transmission costs tracked by the BPA, expansion and sustain. He noted that expansion accounts for 20% and sustain 80%. Jayaweera said the UTC work found 30/70.

Tomás Morrissey, PNUCC, wondered if utilities address T&D in costs or benefits. He recalled that the Seventh Plan had low DR values because the T estimate was bundled into them. Morrissey said it makes it harder to compare them to values without a bundled T value and wondered if there is any thought about moving them for a more apples-to-apples comparison.

John Ollis, NWPCC, said this is convenient for the way the models work and net cost or benefit doesn't really matter to the model.

Josh Keeling, PGE, said he's fine with the Council's method. For T versus D, he was fine with using T but the D looked weird and hand wavy to him. Keeling said it would work for persistent DR but not for what was looked at in the Seventh Plan. Ollis said he will address other resources. Keeling said in the past PGE classified flexible resources like water heaters or batteries and if it's dispatched all the time it will have a D avoided cost but things like thermostats will probably not interact with NCPs (Non-Coincidence Peak).

Jayaweera said this means [Bullet 2] should probably be applied on a product-by-product basis. Keeling called that approach ambitious at this stage.

Hall confirmed that the proposed numbers will be applied to the EE curves and if DR gets T&D then EE will too. He recalled that DR got the T but not the D in the Seventh Plan adding that both were high but are now coming down into more defensible data. Jayaweera stated that EE will have both and the question is should DR have both as well.

Garcia stated that utilities make plans for D investments and then execute them. He asked if any utilities state that DR would make a difference in their D investments. Jayaweera said PacifiCorp was helpful in this discussion.

Fred Heutte, NW Energy Coalition, asked about the substantially reduced values staff received. Jayaweera said previous Plans did not account for the O&M versus growth differentiation of the investment. She added that there was also inconsistency in methodology among T&D planners. Heutte called this helpful.

Ollis added that along with mixed methodologies there were other regions like CA. Heutte called this a classic "what is truth question." He added that after looking at the CTA 2045 water heater pilot, he was thinking about two things: peak load reduction and everything else. Heutte acknowledged that it's hard for the Council to value the second bucket.

Gurvinder Singh, PSE, addressed the [Data Received] slide noting the dramatic change. He said the region looks to the Council for assumptions and the dramatic decrease calls for a White Paper or another detailed explanation as these changes will have a dramatic impact on EE cost effectiveness, especially when there is a capacity contribution.

Morrissey said this varies by utility and recalled a Seventh Plan scenario that was run without T&D and only had a five percent shift in results. Ollis agreed that the numbers changed dramatically but the signal didn't matter to the model.

Bob King, Smart Energy Water, said this number is 20-30% smaller because you are only focusing on growth. He said he did this look in Texas and didn't look at growth and asked why the Council does the opposite. Jayaweera clarified that there's in-field growth and new development and staff tried to exclude new development. She said it came down to data availability and if that data could be parsed out. King said they are building a lot of transmission which may have led to the higher number.

Keeling said a modified version of his comments could be applied to EE. He was uncomfortable with applying "peak" to all avoided cost numbers, as system peak is different than distribution peak. Jayaweera said it will be applied to the coincidence EE load profile with the system profile at the peak profile. Keeling said this didn't make sense to him.

Keeling then agreed with Heutte about peak capacity and everything else, adding that PGE thinks about simple and advanced DR so peak is not one number. Heutte added that the Oregon PUC has a new capacity/adequacy docket and he is going to mull if EE and DR should be treated the same.

Garcia asked if the Council considered broad distinctions between urban and rural or east and west. Ollis said the Council can do east/west but there were only five respondents which is not enough data.

Morrissey nodded to a Seventh Plan east/west break out for gas turbines. Ollis explained the reasons for that and again pointing to the lack of data is this case.

James VandenBos, BPA, asked what is contained in Enablement Costs and Implementation Costs [Slide 8.] Ollis moved to [Slide 9] to explain. VandenBos asked if Enablement and Implementation costs are inclusive to costs to the utility and the end user. Jayaweera answered yes, if the customer has to install extra widgets for control that would be under Enablement costs. VandenBos clarified that this is costs to the whole system from standing the program up at the utility, installing technology to call the event and the end-user technology. Jayaweera said it depends, but generally there are little to no customer costs.

Keeling said PGE has two thermostat programs: direct install and bring your own. He confirmed that in the direct install program the thermostat cost is a cost but not in the BYO program.

VandenBos thought [Slide 10] should say “at least” as the value should be more than the costs. Ollis explained that willingness to pay is the utility avoiding high electricity prices. Jenny Roehm, Schneider Electric, said the first bullet implies that utilities should not pay more than incentive plus costs to do the program. Ollis agreed and asked the room not to think about this from a reliability perspective but an economic one.

Keeling said he had an issue thinking this way because of the instability of the number. Ollis agreed and said he’s defining bad events as high market prices.

Garcia agreed with the sub bullet but felt it was missing avoided capacity expenditures for T&D. Ollis agreed. Garcia added that willingness to pay is equal to the cost you avoid. Many in the room agree with that assessment. Ollis agreed, explained that these numbers work in the model world and was interested if it aligns with the real world.

Heutte was confused about loss of service and at what point it has noticeable value. Ollis said it’s what the customer thinks, the minimum a customer is willing to accept. Keeling admitted that PGE struggles with this question.

Ollis reminded the room that these are planning-level calculations, staff has to generalize a lot and the Council is trying to be conservative. Heutte didn’t understand where to draw the line if the customer doesn’t feel a loss of service.

Singh recalled talk about Value of Lost Load for the second bullet which has been condensed into the more quantifiable loss of service. He wondered if there was any discussion of going from VoLL to this. Ollis didn’t think so saying that this captures a loss of service. Singh said this seems to capture some value that a customer might feel is valuable to them.

Hall said he still has concerns using wholesale/retail rates in the model. He asked for the theory around the ideal that the loss of service equals the retail rate of electricity. Ollis explained. Singh thought the value to the customer is more than just the retail price but quantifying the “more” is hard.

Kyle Frankiewich, WA UTC, said but for the DR program the customer would have been happy to pay the retail price for the energy. Ollis said this is exactly what he meant.

VandenBos said the difference between perceived value and retail rate of electricity should be the quantified loss of service. Ollis said this could work for costs in general but loss of service could be the entire amount and what the customer perceives. VandenBos said the incentive a utility pays for incremental loss of service above the retail rate is the gap financing, so the retail rate plus the incentive should be equal to the value of the energy to the customer. Ollis said maybe and asked him to hold his opinion until he shows the equation.

Heutte said some customers expect a loss of service with some DR programs but a thermostat program is designed to not have a perceived loss of service yet sometimes a customer may perceive a loss. He said this is confounded by a rate-only program. Ollis said staff may have made things too simple and lost meaning.

VandenBos asked if part of the mission is estimating the incentive size that people will pay [Slide 11.] Ollis answered yes, explaining that he was trying to come at the problem from the utility and customer side to create bounds. VandenBos asked if modeling the incentive size requires sizing the incentive so it is called forty times a year. Ollis said this is modeling what the utility is trying to avoid on a perspective basis. VandenBos then asked if this assumes any given utility's marginal capacity resource is the wholesale market price. Ollis said *a priori* it assumes the market price is the best price to avoid negative outcomes.

VandenBos asserted that the incentive needs to be greater than the retail rate. Jayaweera said the retail rate is a proxy for that amount but [Slide 13] shows that cancels out.

Morrissey voiced concern about using the top 40-hour methodology, particularly as the prices out of AURORA tend to be stable compared to historical market. He asked about the avoided cost of capacity. Ollis said he's fine using any price but was not convinced that the avoided cost is the best proxy as the product size is not exactly right. He thought the best approach would use the RPM price, but that is unknown in advance.

Singh said the avoided cost is needed to calculate the TRC. Ollis said the avoided cost is implied in the portfolio trade off decisions, so putting it in here predetermines it. Singh agreed, but said the net program cost will be input and the program will use the avoided cost to determine cost effectiveness. Ollis agreed, using [Slide 16] to illustrate the point.

Phillip Kelsven, BPA, said utilities and BPA are using DR for transmission and river constraints and wondered if wholesale prices are a good way to estimate costs. Ollis agreed that they wouldn't work in a pure sense but do for modeling, particularly with the remodeled GENESYS [Slide 13.] Kelsven was reassured that the model understands adequacy and asked how it relates to the top 40 proposal. Ollis said the top 40 is something he needs to know ahead of designing and pricing a program.

Garcia said utilities will discount the wholesale price when considering programs because they are not sure about participation and the discount reflects utility risk if the customer doesn't respond. Ollis asked if the discount is on the volume or price side. Garcia said both approaches are feasible. Garcia then said, in his opinion, DR will become much more valuable for its flexible capacity as opposed to peak capacity and asked that this value stream be kept in mind. Ollis said the models connect capacity to energy and implicitly to flexibility in the Associated System Capacity Contribution (ASCC.)

Hall asked if Net Cost on [Slide 13] equals TRC. Jayaweera said the basis is TRC. She didn't want to get too caught up on the terminology but said it's a way to value all costs and negative costs for DR.

Hall then asked if this is consistent with how EE is valued and if not why. He said he is looking for an easy-to-explain methodology. Hall then asked if Option 1 is Min top40 wholesale price minus deferred T&D. Ollis said yes, for Option 1. Ollis then said that DR and EE are similar but EE doesn't dispatch and is a must-take resource. Ollis agreed that some DR dispatches but the idea was to come up with something that looks like EE but responds to a wholesale electricity price.

Hall pointed to the values for ELCC assigned to EE and DR. He called it fine but asked for evidence why so he could explain it to BPA customers. Ollis said the ASCC is similar to an ELCC. Ollis said there is more model work to be done but he didn't think that DR could help the hydro system shift because it didn't have much energy. Hall wasn't sure if he agreed.

Heutte said this is going in the right direction as EE is not less than DR but DR is more limited and has but be dispatchable which has a cost. Heutte then said this option suggests that market value misses most of the value.

Keeling agreed. He said he was uncomfortable with Ollis's argument as it hinges on perfect information and rational cost-minimizing actors that have full knowledge. He was more comfortable with using empirical data.

King said this is just setting boundary conditions. Keeling said no, as it is not correct in expectation. Ollis agreed with some of the points and said this was a way to get around using empirical data which is what the DRAC wanted. Ollis argued that this method doesn't imply perfect knowledge and isn't necessarily reflective of what will be tested in RPM futures.

Keeling said it assumes that whoever is setting incentives is doing it rationally and has full knowledge of minimum top hours of wholesale price over the planning horizon. Keeling asked why incentives are in the calculation if it's a TRC. Ollis said they are trying to reflect that there is a transfer payment and asked what subtracting loss of service to the customer means. Keeling called it a mess that he didn't like and explained PGE's process.

Eli Morris, PacifiCorp, agreed that incentives shouldn't be there if this is a TRC test and suggested being consistent with CA protocol and EE. Keeling said this looks like a utility cost test and not a TRC.

Ollis said in Option 1, if you guess the wholesale prices correctly it's a transfer payment. Keeling said we should agree on the conceptual formula before we get to the "how." Garcia agreed that this is true with a regulated utility that's short but that's not everybody in the room. Garcia said for them the wholesale price is what directly reflects what they would do. He said having a single number to reflect two very different scenarios is impossible.

Keeling agreed, saying that implementation costs, plus enabling costs minus value of lost service, minus differed T&D would work for both.

VandenBos said his economic sensibilities exploded when he saw the incentive payment treated as a cost as it's a transfer payment. He said forcing a behavioral shift puts consumers in a less optimal situation which is a cost that should be included. He said calculating that to the loss of service is the issue and the incentive payment gets at it. He said the CA cost effectiveness protocol for DR uses the size of the incentive payment as a proxy.

Keeling said it may as there are programs that cost him nothing and there are a lot of heroic assumptions.

Ollis said it was great that some of PGE's customers willingly ignore utils but said that not every utility can gain that value and it can't be a bound for all DR programs. Ollis asserted that every concern is captured in the calculation.

Keeling asked why there is a transfer payment for EE and not DR. Ollis moved to [Slide 13] to explain his point that DR is a shift in risk. Keeling said this incorrectly assumes how utilities price incentives.

VandenBos asked if Keeling agrees that the loss of utils should be in the cost. Keeling agreed. VandenBos asked how PGE estimates that. Keeling said in a variety of ways calling it a separate conversation. Keeling asked what the conceptual formula should be. Ollis said that two options have been proposed and we need to move forward. Keeling said we should use what VandenBos proposed and not use incentives.

VandenBos said he would use the value of incentives to get at the cost of lost utils. Jayaweera said that's what this is trying to do. VandenBos said he wants to hear different ways at getting to the loss of utils to the customer. Jayaweera and Ollis both agreed.

Ollis pointed to the three proposals: the empirical approach, Option 1 which is similar to what everyone is talking about, and there is no incentive. He then asked how to quantify the loss of service.

Hall said he was uncomfortable with rushing to land this today. He called the work terrific but said more thinking is required and asked what the time table is. Ollis said he wasn't expecting consensus today but was trying to focus the conversation. He said calculations have to be done by November and this is just a small part of all of the work.

Hall asked for the latest date this is due. Ollis said two weeks from now. Hall suggested two or three options and not wait until the August DRAC to work on this. He then suggested understanding how it compares to the EE and CA method. Jayaweera suggested one-on-one meetings with Keeling, BPA and Morris and a webinar later.

Morrissey recommended an IRP scrape and examining the BPA study to see if the numbers are in the same ballpark.

VandenBos asked to see the size of the issue along with alternative methods. He described the CA method, which he called a blunt instrument and the possible need for something more granular. Jayaweera said that was part of the last proposal and it was questioned.

Heutte asked why the minimum of top 40 hours was chosen over average. Ollis admitted that he thought that would be the big discussion of the day. Jayaweera said the assumption was that the DR could be dispatched for 40 hours and you want to be in the money.

Someone on the phone asked about all of the proposals. Ollis said there are four

- No incentive
- IRP scrape of the region
- CA cost effectiveness protocol
- Avoiding top 40 market hours

Morris said regardless of how incentives end up in the levelized cost calculations he thought there could be a good conversation about how assumed incentive levels effect participation rates in the supply curves. Jayaweera agreed.

LUNCH

**EE & DR Interaction**

Hall asked where DR attrition will be modeled [Slide 6.] Jayaweera answered that it is under cost analysis of DR.

VandenBos asked if the RPM knows that a DR product might get smaller in the future. Ollis explained that it's an agent-based model and the agent doesn't know things ahead of time. Ollis continued saying it should fall out in the optimization. VandenBos asked if the model knows beforehand that DR may be smaller if it interacts with commonly picked EE bundles. Jayaweera said that is the proposal but admitted that it's hard to know how much EE is adopted *a priori*.

Hall asked for an expanded explanation about the proposal of using a specific value for DR vis-à-vis EE [Slide 4.] Ollis said the ASCC is an attempt to be more dynamic and represent the capacity contribution of each sub portfolio. Hall said it sounds like the ASCC will be assigned to the resource instead of being derived from the model. Ollis answered no, the ASCC and reserve margin are trying to encapsulate operation fidelity.

**Non-Firm DR**

Keeling called critical peak pricing dispatchable as it's a called event [Slide 2.] Ollis asked if there's a control that shuts down power. Keeling said there's no controlling device but it is called. Ollis confirmed that none of these have a controlling device. Keeling agreed.

Garcia clarified that this means if a pricing threshold is met then the resource will be available. He said this is the opposite of his earlier point about an owner opting out of a called DR event. Jayaweera said this is the same concept as there will be an impact adjustment based on opt in choice. Garcia agreed, but said the number of times you call an event will have an effect.

Roehm asked if this is voluntary and customers face no penalty for not participating. Jayaweera pointed to PacifiCorp's four-point classification matrix.

Frank Brown, BPA, asked if a water heater time clock is non-firm. Jayaweera called that firm. Keeling said PGE struggles with this saying they use dispatchable/non-dispatchable and firm/non-firm.

Keeling asked where peak-time rebate is on the proposed products slide [Slide 5.] Jayaweera said she called it Critical peak pricing for Res and Sm Com and Interruptable Tariff for Large C&I. Keeling suggested splitting out Res and Sm Com out as impacts, costs and adoption rates are very different and offered supporting data.

Ollis asked if there is consensus around a best-in-class between the carrot or stick resources. Keeling called it a contentious issue. Roehm said there is no consensus. Keeling cautioned against this thinking as a lot comes from summer peaking utilities and their rules of thumb don't necessarily apply. He then explained PGE's rules for participation adding that they found conservation impacts.

Jayaweera confirmed that energy impacts mean PGE gets KW and KWh reductions but the EE is separate. Keeling said they measure impacts during persistent peak, persistent off peaks and events which saves 200 KWh per household.

Hall said because of DR, the awareness of conservation goes up. He then asked if the products add up to 100. Jayaweera said not necessarily, saying there needs to be discussion around exclusivity versus overlap. Hall pointed to all of the options that a company could have and asked about how to estimate them. Jayaweera agreed that is an issue. Hall reminded the room that we're talking about potential on actual programs.

Keeling asked if this will only be modeled for utilities that already have AMI. Jayaweera said many utilities are rolling out AMI and we might limit it to only AMI unless we know there are more coming. Keeling asked if opt in/opt out will be modeled. Jayaweera agreed that will be a difficult question that will be addressed. Keeling said PGE treated opt-out as a scenario.

Heutte called the PGE test bed a natural experiment and asked when data is expected. Keeling said it will take longer than a year saying the question is how it interacts with the broader portfolio.

**DR Transfer Agreement**
Heutte asked for further explanation of [Slide 4.] Mike Starrett, NWPCC, explained that the first is a specific resource delivered and the second is a tag of generic energy out of a BA. Heutte said that is not what the labels say to him. He continued, pointing to the complexity of the issue and wondered how to abstract a general approach that assesses what's feasible versus what is not. Starrett explained that these were originally framed as transmission products but after discussion with PGE were re-framed around the power contract pieces.

Heutte wondered if this would affect slice block or slice only customers. Starrett called that a glass bubble and couldn't offer any insight.

Garcia said he discussed the scenario on [Slide 5] when he was at Tacoma and hourly firm redirects were being questioned. He said at the time they were told no; they can't take power sunk to their territory and sink it someplace else. Starrett said that was their informal understanding.

Heutte said [Slide 6] is akin to his generic example. He pointed to areas that are consistently long or short and acknowledged that the region will not have a fully optimized uniform market any time soon but wondered how to fit the pieces together. Huette said the CA ISO takes DR from anywhere and wondered how to aggregate DR from BPA's customer utilities. He felt a BPA backed DR capacity product could be very valuable and said this approach comes close but wouldn't be limited to requirement customers. He said expecting each utility to manage its own DR in isolation is like not having an EIM and doesn't optimize the system.

Hall clarified that BPA will always treat loads a utility serves as loads they will not directly contact. Heutte felt that in some cases there has been the opportunity for some contact between BPA and the end-use customer. Hall agreed, but insisted that BPA will always involve and go through the utility.

Keeling asked why DR can't be treated as a generation resources and tagged directly. Starrett said that is the second scenario [Slide 4.] Keeling asked why re-export is not an option for the full requirement customers too. Hall pointed to a layer of legal and statutory requirements that says there is an expectation that utilities will use power to serve load. Hall said he was sympathetic to the idea but said it's not quite there yet as a starting point.

Garcia agreed that federal law requires this. Keeling said DR is generation and not load. Garcia said this is a legal question and general counsel for utilities and BPA agree is not allowed. Keeling asked if FERC rule 745 applies. Hall said officially no, but we try to adapt as much as we can under FERC rulings and regulations.

Hall then countered the argument of treating DR like a generating resource through accounting, saying the utility is using it to serve someone else and make money. Keeling asked how it's different than a utility making and selling hydrogen out of their excess power. Hall said this is the legal construct and acknowledged that it is different for IOUs.

Starrett asked if someone from BPA legal could clarify some things around the BPA Contracting Block on [Slide 4.] Hall said maybe but not to expect the general counsel office to sign off on any rules.

Ollis said there's some frustration about the law because the current set of contracts doesn't quite fit the current situation. He noted that things change and this could be an interesting topic to keep in mind as the region moves forward.

Hall voiced confidence in BPA general counsel and said that Bonneville cannot lobby for these types of changes. Ollis thought Council Staff could get a lot of nuance and information from a discussion with general counsel. He understood why this is a sticky situation for BPA but stated that contracts get re-negotiated and this is far enough in advance that it may be the right time to bring this up.

Garcia said that it wasn't contract law but Federal law that's driving general counsel.

King asked if part of the law defines DR as a demand reduction. Keeling said the issue is interpreting what load means. He added that FERC called DR a generating resource that can serve, which means that load is net DR.

Hall said he will ask general counsel to come in but did not guarantee they would. He stressed that this is not a nuanced opinion but is rooted in the statute and general counsel has gone over it many times. Hall said he would make an appeal, again pointing to their previous work.

Garcia said he agreed with everything Keeling said and would be great if could work legally. Hall said he cannot represent anything outside of what is in the statute.

Heutte thought FERC designated DR as a generating resource in the context of an organized market, which the Northwest doesn't have. Heutte said he sees DR as an INC or DEC. He then said BPA full requirement customers would face significant obstacles to reselling to a third party but selling back to BPA is a different thing. He said a partial requirements customer might be able to finesse the issue. Heutte concluded by saying the question for the 2021 plan is to find the potential for this transfer approach.

Starrett said he sees value in bringing BPA's general counsel in to bring clarity to some of these questions. Hall said he couldn't guarantee they will come.

Keeling asked if the potential will flag DR that is not liquid. Ollis said that's a question for the 2021 Plan and all the options are open.

**BREAK**

**Climate Change – Impact on DR**

Keeling asked if Massoud Jourabchi, NWPCC, modeled the change in AC adoption [Slide 3.] Jayaweera answered yes, explained his process and said building stock growth increases AC adoption too. Heutte said population growth could be a factor as well.

Keeling said the issue around [Slide 4] is about timing and run off because of less snow pack. Ollis agreed that it's a timing and run off issue and he will continue to report back as more adequacy studies are run.

Hall noted that climate change data is not applied to the characteristics of DR. Jayaweera said not directly but they will be applied to the load forecast parameters that is carried through to DR, using AC saturation as an example of the kind of data they will take. Hall asked if the amount of DR will change based on capacity need. Ollis said it will likely be that seasonal attributes will have a different value so if there are more summer events then bins that have some summer value will have more value in this Plan. Hall asked if this will increase the amount of summer DR. Ollis said maybe, as there may be other resources the model may choose.

Keeling said that PGE's IRP found some complex dynamics with multiple season DR.

**DR Products Lighting Controls & EVSE: Supply Curve Development**

Hall asked who is responsible for developing the supply curves [RTF Scope.] Jayaweera answered that she is, using input from other potential assessments, expert opinions from around the country, and the DRAC. Hall assed which assessments. Jayaweera said BPA's, PGE's, Avista's, Idaho Power's and more.

Hall asked if those resources are available to other members of the DRAC. Jayaweera said as much as they are publicly available. Hall asked if we could compare BPA cost numbers to the others through the DRAC. Jayaweera said she will be compiling them but you could go directly to the utility.

Heutte asked if [Per Unit DR Potential Preliminary Estimate] is current data. Jayaweera thought it was 10 years of historic data. Keeling cautioned that this market is changing rapidly and will need constant reanalyzing.

Heutte said the most common level 2 chargers are 16 and 30 amps making them look like an electric resistance water heater for peak except water heaters only run for 10 minutes while these can run for a couple of hours. Jayaweera pointed to many variables.

Jennifer Light, NWPCC, said this represents fleet-weighted average over 10 years and said there's data for a more recent set of years that the DRAC could use. She said the RTF spent time on determining how much charging happens at home versus offsite that the group can look at.

Keeling asked about the duration of the capacity. Light said this is a one-hour event.

Keeling said they are planning for a 50% throttle [Slide 9.] He was concerned with using one hour over duration. Jayaweera agreed that it was tricky and still developing. Ollis further explained how this information would flow down into the model. Keeling pointed to a terminology issue when talking about one-hour versus four-hour or seasons. He said four-hour average capacity is a higher bar and would welcome the commission looking at one-hour capacity, but there should be consistency around terminology.

Hall said that BPA de-rated some DR because it couldn't meet what we modeled, but did say the cost of DR is based on a 40 hour per season contract. Keeling said PGE uses similar terminology.

Light said the RTF uses one hour because they didn't have a product definition.

Heutte confirmed that de-rate doesn't presume that a less-than-four-hour resource doesn't get counted at all. VandenBos said yes, it's spread out. Keeling said PGE's de-rate doesn't work like that. He said if there's a DR program that showed up with six KW for two hours and 0 for two hours it would be three for the four hour event and de-rating would start from there.

Heutte said shifting EV load off of peak is much more than 40 hours a year. Jayaweera agreed.

Frankiewich said the numbers on [Per Unit DR Potential Preliminary Estimates] are very conservative and new technology will have a higher KW maximum. Jayaweera said they can look at the last two years or some trending information. King said commercial chargers are seriously ramping. Frankiewich revealed that some WA IOUs are still in the pilot stage and trying to figure out what is most effective. Jayaweera agreed that it will be challenging to account for overlap between customers that are on a TOU and DLC and the kind of response to expect.

Frankiewich said it boils down to use case and load forecasts. He suggested adding a location parameter to [Slide 9.] Jayaweera said the RTF work has focused on residential charging. King asked about commercial networks pointing to a GM announcement about commercial charging stations. Keeling said that would be non-firm. King felt they would be open to a conversation about DR. Keeling said they are open to dynamic pricing but not load control.

Frankiewich said the WA commission envisions this as a pilot program for that reason and they are trying to get ahead of what could be a huge impact on their system. Keeling said they forecasted all of the segments in their load forecast and IRP and this is the most important by far.

Jayaweera reminded the room that the next meeting is on August 21 with a webinar in between. Ollis thought everyone did a great job today. Jayaweera adjourned at 4:00 pm.

**Attendees**

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| Tina Jayaweera | NWPCC |
| John Ollis | NWPCC |
| Nicolas Garcia | WPUDA |
| Tomás Morrissey | PNUCC |
| Bob King | Smart Energy Water |
| Jenny Roehm | Schneider Electric |
| Josh Keeling | PGE |
| Adam Schultz | ODOE |
| Bud Tracy | Independent |
| James VandenBos | BPA |
| Lee Hall | BPA |
| Kyle Frankiewich | WA UTC |
| Fred Heutte | NW Energy Coalition |
| Jason Salmi Klotz | PGE |

**Attendees via Webinar**

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| Andy Eiden | PGE |
| Brian Grunkemeyer | Flex Charging |
| Clint Gerkensmeyer | Energy Northwest |
| David Jackson | LMCO |
| Danielle Walker | BPA |
| Elizabeth Osborne | NWPCC |
| Eric Shum | RTF CAT |
| Ryan Finesilver | Avista |
| Frank Brown | BPA |
| Jennifer Finnigan | SCL |
| Anna Karmazina | Oregon State Univ |
| Phillip Kelsven | BPA |
| Torsten Kieper | BPA |
| L McCarty | Flex Charging |
| Malcolm Ainspan | NRG |
| Eli Morris | Rocky Mountain Power/Pacific Power |

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| Quentin Nesbitt | Idaho Power |
| Will Price | EWEB |
| Sarah Vorpahl | WA Dept of Commerce |
| Shirley Lindstrom | NWPCC |
| Gurvinder Singh | PSE |
| Stephanie Pettit | BPA |
| Zeecha Van Hoose | Clark PUD |
| Brian Dekiep | NWPCC |