Demand Response Advisory Committee
Northwest Power and Conservation Council
December 12, 2019

Tina Jayaweera, NWPCC, began the meeting at 9:30 AM with introductions and a look at the agenda.

Non-Residential DLC/Space Heating DLC
Jayaweera confirmed that BPA is using a seven-year ramp rate. Joan Wang, Cadmus, confirmed that seven years was used for most of the residential and non-residential dispatchable product with a few exceptions for less common products like thermal storage.

Jayaweera noted that Council staff is using five years for residential/small commercial but could change it. Frank Brown, BPA, said the Cadmus report was designed to be conservative but he was comfortable with five for the commercial sector.

Demand Curtailment
Wang asked if the $40/KW incentive accounts for a duel-season product as Cadmus only recommended $20. Jayaweera answered yes. Lee Hall, BPA, asked how many hours that represents. Jayaweera answered 40 hours a season. Hall confirmed that number is consistent with BPA's assumption. Jayaweera added the seasonal/yearly hours to the spreadsheet for clarity.

Demand Voltage Reduction (DVR)
Brown explained that, depending on a utility's plan, some amount of the $100/KW Equipment Cost could be considered an incentive. He called the amount generous, explaining that equipment may not cost that much but the utility can cover incremental costs with whatever is left over or keep it as profit.

Zeecha VanHoose, Clark PUD, asked what was included in O&M costs. Brown wasn't sure, agreeing that it's high. Hall said someone will get back with an answer.

Brown said there was an assumption that a number of utilities were implementing modest DVR programs at their own pace and that would generate some annual amount of engineering and staff costs. Brown said the number represents between 10 and 12 utilities implementing DVR over a five-year period with each needing between $15,000 to $18,000 in labor costs. He was not sure how to convert that number to a regional cost estimate. Wang agreed.

VanHoose said Clark has done some CVR but no DVR and found that there is a set-up cost but no annual O&M costs. Jayaweera agreed this will be challenging and suggested using a $/KW instead of a $/year metric. Brown thought that would be a better approach but didn't know what the number would be and offered to come back with one.

VanHoose asked if this would apply to the set-up cost as well. Brown characterized the set-up cost as unique to the structure of the Cadmus analytical work, explaining that the number represents work from both a BPA and utility employee. He said this number is the same for all products.

Hall said this was a way to ensure all costs were accounted for. Hall asked if studies found between 100-200MW DVR potential in the BPA service area. Brown said running the levelized costs models revealed that it didn't matter what you put in the first year so they left the $150,000.

Wang added that the levelized cost for DVR came to about $13/KW-y. She said the $225,000 O&M estimate assumes 85 BPA customer utilities participate and spend 40 hours a year on general program costs.

Fred Heutte, NW Energy Coalition, said the numbers seem to be in a reasonable range to support a program when compared to Distribution Efficiency Initiative (DEI) and Energy Smart Utility Efficiency (ESUE) work he's seen.

Hall said those programs are for CVR and the best numbers are represented here by the Cadmus work. Brown spoke about the different DVR pilots that Cadmus used, cautioning that the work was adjusted to account for today's end-use loads.

Jayaweera said this topic came up in conversations about CVR during the CRAC meeting and asked for data around the adjustment. Brown said he's done DVR studies in the last five to six years and noticed that reduction is nearly cut in half. He concluded by saying don't believe work prior to 2010.

Irrigation
Jayaweera explained how she divided the load after the last DRAC meeting and asked if members were comfortable with her approach. Brown stated that large factory farms with sophisticated metering and sensors are more efficient on average than small or medium farms. He then said that crops are crops and an acre of alfalfa needs the same amount of water no matter the size of the farm.

Heutte said larger farms may be able to afford more sophisticated equipment but data is sparse. He approved of Jayaweera's approach. Brown approved of keeping the ratios the same for small/medium/large farms.

Price-based DR Overview
Tom Eckhart, UCONS, asked if the modified product definition is for all DR. Jayaweera answered that it's just for price-based DR.

Heutte called it interesting the PGE is not starting with 100% of their customers for their residential TOU test bed, adding that about 22% opted out [Products for the 2021 Plan.] Heutte added that of the 15,000 that opted in about 3% dropped out over the summer. He concluded that opt out gets a different result than opt in.

Jayaweera stated that Ontario has an opt out but everyone else is doing an opt in.

Wang said the Cadmus study just looked at the CPP product but assumed the utility had a TOU structure in place.

VanHoose stated that utilities without AMI might still be able to offer controllable products [Overlap with Controllable DR.] She wondered how to tease out the AMI component in the price-based products. Jayaweera noted that Bryce Yonker, GridForward, stated that AMI was becoming more prevalent regionwide.

VanHoose said her utility is not planning on rolling out AMI any time soon. Ahlmahz Negash, Tacoma Power, said her utility is. Jayaweera stated that 80% of regional customers have AMI in their region.

Hall said VanHoose brings up a good point for BPA customers with no plans to add AMI. He wasn't sure how to address the cost disparity but thought it should be addressed.

Jayaweera was inclined to limit participation based on those with AMI. She was hesitant to attribute the cost of AMI to a DR product because it has more value than a TOU program. Hall agreed but wondered how to estimate that out over a 20-year horizon.

VanHoose said TOU and CVR/DVR are two different things and without AMI a utility is limited. She asked that this be kept in mind when capturing the total potential of these programs. Jayaweera said this can be addressed when talking about eligibility.

Eckhart said his experience tells him that economics are not as important with Res DR customers as it is with C&I DR customers.

Bud Tracy, consultant to Idaho, agreed with Hall saying there needs to be a signal around participation for both the utility and end-use customers. Hall clarified that this is a modeling exercise designed to reflect both what's on the ground now and how that may change over the Plan's 20-year lifespan. Hall stressed that encouraging or discouraging participation is not part of the exercise.

BREAK

Jayaweera stated that she found EIA data around AMI that she will analyze and bring back to the DRAC

Price-Based DR Workbook
Res TOU

Negash addressed AMI equipment costs, suggesting using utility business case numbers. Jayaweera said she could but didn't know how to cost it. Hall thought using costs incrementally and saying 80% are eligible now based on current saturation of AMI might be one approach. Negash agreed.

Jayaweera asked about comfort with limiting participation to utilities with AMI and assuming cost of existing deployment of AMI are sunk costs. She said this might not reflect what will happen over 20 years but could be good from a planning perspective. Hall called this the most conservative approach, similar to BPA's approach with batteries.

Heutte suggested looking at PGE's cost data as it is current. Jayaweera called that a good idea.

Res CPP

Jennifer Snyder, WA UTC, wondered why the lowest number, 6.3%, was chosen for Peak Load Impact and suggested using 7.5% as it would be a better match. Jayaweera asked about any differential impact between summer and winter. Wang said it was different by season.

Negash asked if this will be opt in. Jayaweera answered yes adding that she hasn't seen an opt out CPP program.

Non-Res CPP versus Interruptible tariff

Jayaweera asked about preferences of one over the other. She added that she's leaning toward CPP as it's more common than Interruptible. Wang didn't recall choosing between the two for non-res, stating that interruptible looks more like demand curtailment except for the incentive structures. She said they did have real-time pricing for industrial customers.

Jayaweera asked about outside the region. Wang said she's researched non-res CPP out of California and found they target small/medium/large, calling it broad program while interruptible tariff might be more appropriate for large customers.

Jayaweera said they could have both but is inclined to use the CPP as there might be a question about overlap. She asked about marketing costs, noting that PacifiCorp used a range, and offered to break the costs into small, medium and large by square foot.

Brown agreed that it makes sense to have one marketing cost and $200 is in the middle.

Jayaweera then said she used PacifiCorp's number for Peak Load Impact. Wang said the California evaluations found a range between 2.5% and 12%.

Industrial Real Time Pricing

Tracy asked how utilities identify large or extra-large customers. Jayaweera thought it was based on monthly demand. Tracy asked if it was the same levels. Jayaweera didn't know, saying that PacifiCorp uses demand but didn't know if their extra-large is the same as another utility's extra-large. Tracy said rate classes are different between the utilities. Jayaweera said she's going with a single value. Tracy called that reasonable.

Wang said the BPA study assumes a longer ramp period for non-firm products. She suggested assuming a slower ramp for AMI as well. Hall asked if that was explicitly called out. Wang said there was an assumption that whoever participated in the program has AMI so there were no equipment costs. She said the longer ramp period will allow the possibility for more adoption and more participation

VanHoose countered that SnoPUD doesn't have AMI but real time pricing can still apply as their large industrial customers have interval metering. Jayaweera agreed.

Quentin Nesbitt, Idaho Power, said the billing system is a bigger issue for Industrial Real Time pricing as making just one little change requires a big IT lift. He then said they had an interruptible customer that used a special contract unique to them. Nesbitt added that they wanted to pay market price for power some of the time but when the energy crisis hit, they had to shut down. Jayaweera called that a good lesson.

Hall asked how program exclusions--where a customer can only pick one program--will be modeled. Jayaweera said it's only modeled in program participation. She was concerned with the possibility of finding that there is more participation in both programs than there would be separately. She added that the concern is tempered by low participation.

John Ollis, NWPCC, said the RPM is not that dynamic in its acquisitions and cheaper is better.

Negash clarified that program participation shouldn't add up to more than 100%. Jayaweera said yes and opened to workbook to illustrate. Hall called these numbers theoretical and was concerned that the real numbers could be off due to overlap in participation between the two.

Jayaweera clarified that the 9% maximum participation means 7% for price-based and 2% for controlled. Hall said 5% would be the max and didn't think it was correct to add the 5% and the 4% as some of the 4% of DLC might opt into CPP and vice versa.

Ollis asked if Hall has seen a lot of overlap. Hall answered no as they are exclusive. Jayaweera agreed that these numbers are likely incorrect. Hall said there's a finite number of customers but there is no empirical data for the programs.

Nesbitt was on the fence but said the same customer might have a higher propensity to participate in both.

VanHoose asked if overlap changes the acquisition of DR. Jayaweera answered that it may but the assumption is you can't to avoid double dipping. Hall confirmed that you can't reserve load for DLC and participate with CPP or TOU.

Ollis recalled that PGE said they hope to get people interested in DR by offering a TOU rate and then DLC. He called TOU "gateway DR."

Jayaweera stated that price-based is probably less expensive so more likely to be picked by the RPM. Ollis thought it would be interesting to see the final costs adding that the binning matters. Nesbitt agreed, wondering if you could reduce participation after everything in bin one and two was picked. Ollis cautioned against trying to make the RPM dynamic.

Additional Morning Comments
VanHoose asked if there was a way to approach product selection that might reflect what utilities actually do. She said if Clark PUD needed DR they would go after large loads first as it reduces customer complaints even though it's more expensive. Jayaweera answered that the Plan prioritizes economics but the action plan and narrative could recognize this phenomenon.

Heutte added that big industrial loads do offer a big bang for the buck but work-hour load will not help much with morning/evening peaks which is more driven by residential load. He pointed to BPA's shift in EE thinking that emphasizes the peakier, residential effects and asked that it be considered in program roll out.

Ollis agreed, adding that because of the amount of flexible hydro there might be DR that's not coincident but still helps with peak. Heutte responded that the devil is in the details, pointing to South of Allston issue in August where conditions vary.

Eckhart asked how far ahead the Plan looks. Jayaweera answered 20 years. Eckhart said he's seen hydro played both ways, and the renewable portfolio also leans on hydro. Ollis agreed, saying the NW has to consider how far the hydro system can flex.

LUNCH

2021 Plan Scenarios
Ben Kujala, NWPCC
Negash voiced confusion over [Slide 16] asking if the highest cost of carbon is used as the base case. Kujala said for the Seventh Plan whatever was put in the model was backed out and incremental costs were added to system costs. He said this was not a fair way to represent system cost implications.

Negash asked if this assumes a social cost of carbon for the whole region. Kujala answered yes and that it can always be backed out.

Heutte thanked Kujala for the explanation calling the change important as everyone wrestles with greenhouse gas emissions. He pointed to PSE's current work on adding the Social Cost of Carbon to the IRP process but wasn't sure about Avista or PacifiCorp.

Huette then said that the Social Cost of Carbon is a damage cost not a mitigation cost, making it something to be avoided. He called this a new concept the region has to deal with.

Ollis said this will be addressed again in the SAAC and that meeting might be a good forum to talk about effects. Heutte hoped that the Council and the WA Dept of Commerce maintain good communication.

Eckhart asked about new plans for peakers. Kujala said the GRAC is working through that potential and the more general pressure is finding places to put any gas resource, peaker or combined cycle. Ollis noted that there is no uniform policy throughout the WECC so there are places gas could be built.

Eckhart asked if there is any change in the definition of spinning reserves. Kujala said there's no change in definition but, in his opinion, thinking is changing around renewables and reserves. Ollis said non-spinning reserves could also be considered an insurance product.

Heutte pointed to PacifiCorp repowering Naughton 3 with gas and Northwestern Energy is seriously considering gas. Kujala agreed but pointed to challenges in Montana. Heutte agreed that they have gas but no pipe.

Heutte pointed to the newly-released Western Flexibility Assessment that addresses decarbonization given state policy and grid constraints [Slide 20.]

Heutte said this Plan has to inform contracts in the post-2028 era [Slide 24.] Kujala agreed but said he must stay within the Council's role. Heutte understood, stressing the importance of providing actionable information.

Eckhart asked about risk of reduced reliance due to increased summer loads and lack of intertie [Slide 23.] Kujala said the assumption of no summer market may have to be re-examined, particularly with the re-developed GENESYS. Ollis called attention to the planning reserve margin on the right axis of [Slide 11] showing that is long.

Heutte added it's vital for the Council to look at the import issue as there may be imports available in the summer. He stressed the importance in examining this dynamic situation.

Jayaweera ended the meeting at 2:00.

Attendees

Tina Jayaweera	NWPCC
John Ollis	NWPCC
Ahlmahz Negash	Tacoma Power
Lee Hall	BPA
Fred Heutte	NW Energy Coalition
Bud Tracy	Consultant to Idaho

Tom Eckhart	UCONS
Zeecha VanHoose	Clark PUD
Joan Wang	Cadmus

Attendees via Webinar

Aaron Bush	PPC
Dhruv Bhatnagar	PNNL
Cindy Wright	SCL
Clint Gerkensmeyer	Energy Northwest
Elizabeth Osborne	NWPCC
Frank Brown	BPA
Suzanne Frew	Snohomish PUD
Jennifer Snyder	WA UTC
Laura McCarty	Flexcharging
Quentin Nesbitt	Idaho Power
Ted Light	EES Consulting
Villamor Gamponia	SCL
Brian Dekiep	NWPCC