

Northwest Power and Conservation Council
Demand Response Advisory Committee
August 21, 2019

John Ollis, NWPC, began the meeting at 9:30 with introductions and a review of the agenda.

DR Transfer Agreements

Tom Miller, BPA

Tim Johnson, BPA

Ahlmaz Negash, Tacoma Power, asked what a utility needs to show to ensure they are selling their own resource and not BPA's. Tom Miller, BPA, suggested the utility schedule the energy out of its own BA and not the MidC to establish that the resource is not from the Federal System. He continued, saying that utility resources dedicated to meet contracted load must still be met before buying resources from BPA.

Miller explained that while BPA resource cannot be resold, tagged resource scheduled from the BA, that is not required for load, can be. Tim Johnson, BPA, added that curtailed industrial loads can also be resold. Miller continued, saying BPA can sell surplus power and that BPA surplus power can be resold by the utility because it is not specified for load.

Tina Jayaweera, NWPC, asked how BPA designates firm surplus power. Miller explained the process saying it's done on an annual, critical water year basis.

James Vanden Bos, BPA, clarified the surplus concept comes from the 1937 critical water rate case settings. Johnson said this is about establishing the content behind the federal dams to produce firm power. Johnson acknowledged seasonal variety that might produce some spring surplus but said this process is about finding the firm component and meeting obligations.

Nicholas Garcia, WPUA, asked if a BPA block/slice customer can use energy from the slice portion for DR. Miller said no, as a block slice contract (referring to section 5B1 of the Northwest Power Act) is still a requirement contract just like a block or load following contract. Miller further explained that a block/slice customer gets a portion of seasonal surplus. Miller then said a utility would have to meet a monthly standard called the Requirement Slice Output test after the fact each month and if they sold DR from the slice, they would be violating their contract.

Fred Heutte, NW Energy Coalition, asked if Rate Case Tier 1 is used to determine the availability of firm power. Miller clarified that the process uses the Whitebook which is a 10-year projection. Heutte pointed to complexities around 5B1 and wondered if they would come into play during 2028 contract negotiations and if they could become more DR-friendly. He mused about how an aggregator like BPA can find a way through the legal maze that would benefit both BPA and the utility.

Negash referenced past conservation transfer agreements and asked if DR transfer agreements would hold up if BPA had firm surplus. Miller explained the past relationship and said it could be done again if there was surplus firm power available.

Ollis stated that there are two legs to any power transaction: generation and transmission. He asked how BPA would treat a different point of sale, wondering if a creative sale would raise a red flag. Johnson understood the economics of the market but said that BPA is not a regulator and urged simplicity. Johnson did agree that this issue may come up again in the “big tent” contract negotiations.

Garcia pointed to a past failed experience trying to avoid a transmission constraint by taking BPA power but not sinking it to the utility. Miller agreed, adding that tags contain a great deal of information and will get more complicated in the future.

Ollis stated that tag tracing provides answers. Miller stated that he hopes not to exercise that capability. He acknowledged that congestion management may be accommodated on a temporary basis but becomes a problem if it’s sustained. Miller also agreed that DR will be closely considered in the next round of contract negotiations.

Jason Salmi Klotz, PGE, asked if there is any written record of this policy. Johnson said yes and directed him to look for the 5B/9C policy on the BPA website. Jayaweera indicated a link to this policy will be added to the DRAC agenda page. Johnson noted that DR is not conservation but load reduction which is something BPA has done before with their DSI customers.

Salmi Klotz asked if there is planning for DR and if that creates a surplus. Miller said it depends, adding that DR is not a unified concept. Salmi Klotz worried that the set up means that DR is not something that could ever be planned for or relied on. Johnson said the compliance of a NERC N-1-1 condition might be met with planned DR.

Miller went back to the issue of DR producing firm surplus power, saying firm surplus power is available every hour of the year. He said the DR will have different availability depending on how it’s structured, but positive, permanent load reduction is considered no load.

Salmi Klotz wondered if and how the DR will be put in the planning process and how that will affect firm and seasonal surplus. Miller said DR will not affect firm and it’s not clear that it would be seasonal. Johnson explained surplus of a certain duration that would be firm, using the PGE deal as example.

Heutte stated that flexible demand is more elastic than DR and a device capturing oversupply when they hydro system is short could increase BPA’s supply of firm power. Heutte then said the conversation will shift from BPA’s carbon-free power to include Bonneville’s ability to leverage clean energy resources throughout the grid. Heutte said e-tags do not include environmental or carbon attributes and should be considered. He concluded by noting that BPA is moving into the EIM which is new and complicated. Johnson said BPA is not disaggregating

the system but aggregating into three, distinct LMPs and will have more clear information on that.

BREAK

DR Dispatch Cost

John Ollis, NWPCC

Heutte noted that the RPM is quarterly [Slide 2] and wondered where Seventh Plan events happen. Ollis said DR is dispatched in the RPM. Heutte asked how the model judges a locational need for DR. Ollis explained the dance between GENESYS, AURORA and the RPM noting that the RPM is a broad way to find out if a resource is in the money.

Heutte stressed the importance of capturing the full value of DR and asked how the model can do this. Ollis said they may lean more heavily on higher-fidelity models to reflect a quickly changing system.

Tess Jordan, PGE, asked what would happen if the entire cost structure for DR on [Slide 3] is fixed and not variable. Ollis said they can get to that as there are other ways to recover costs. Jordan called this a market versus avoided cost construct. Ollis somewhat disagreed, saying he is trying to get the right “hours of dispatch” number and the right amount of expensive electricity avoided.

Tom Brim, BPA, asked how resources are contracted when acquired, pointing to different approaches in the models [Slide 7.] He pointed to BPA work around acquiring DR on a pure market basis and found that the variable costs do not come into play. Ollis added this comment to the slide.

Heutte asked for further explanation around fixed and variable costs. Ollis explained.

Vanden Bos saw two uses for this value. For determining a logical dispatch for DR he supported comparing the actual marginal cost of the resource to the market value. Ollis said he needed a price for it to perform in the model. Vanden Bos said the other use is calculating a value and asked what is done with that value. Ollis agreed, saying the resource needs a variable value that overcomes fixed cost to be built in the RPM, adding that the RPM also builds for other reasons. Ollis said the question is how variable value should be calculated and how much credited.

Garcia agreed with the proposed approach adding that it’s important to capture the willingness of a DR partner to dispatch, noting that it changes over time. Ollis added the comment to the slide. Garcia suggested a discount to reflect that DR is not always available.

Jordan said you don’t treat all programs the same and suggested a distinct price to trigger dispatch as a proxy. She then asked about the implications of DR modeling in the RPM. Ollis likened it more to an avoided cost. Jordan asked if DR model results are used to determine needed alternative capacity resources. Ollis called this tricky and explained how information

from GENESYS and AURORA guide the RPM. Jordan explained that she models DR as completely fixed and doesn't use market price minus incentive to find savings. Ollis said this could be captured and is in line with his thinking.

Bill Henry, dJoule, said the picked price must reflect the hottest day. Ollis said an RPM enhancement could be done but the dispatch cost doesn't have to be the hurdle cost. Henry asked how a use limitation is represented. Ollis said it's not here but in the adequacy calculation.

Quentin Nesbitt, Idaho Power, asked if the RPM looks at an inadequate scenario. Ollis said the RPM looks at many futures and some have adequacy issues, adding that DR is bought for those tail futures. Nesbitt then commented that variable value used for market price makes sense but not for adequacy. Ollis said adequacy criteria is somewhat separate from market considerations and DR is a cheap solution.

Vanden Bos confirmed that any costs netted of the benefit are not already accounted for in the levelized cost. Ollis agreed.

Heutte pointed to different tail risks like low hydro or gas delivery issues. He said there might be cases where the incentive, or variable cost, are significant and might belong in the model. Ollis agreed saying he's willing to make up a cost but wanted the DRAC to see the issue.

Vanden Bos recalled his original comment, "use actual marginal value of product for dispatch" as this is about making DR behave in the model. Ollis removed the comment from [Slide 7.]

LUNCH

Residential Direct Load Control

Tina Jayaweera, NWPCC

Suzanne Frew, Snohomish PUD, asked where heat pumps fall on the categories outlined in [Slide Res Direct Load Control Products.] Jayaweera answered that HPs would be in both Space heating and Air conditioning adding that she didn't know that there is ongoing heat pump CTA 2045 work. Jayaweera said this may alter things a bit.

Electric Vehicle Charging

Frew said FTE may not be the best way to calculate cost parameters as there are many different delivery models, including the third-party model, which is less expensive. Jayaweera admitted this will be difficult from a regional perspective and asked Brim how BPA approached the issue. Brim said admin set up costs were included knowing some programs would hire external parties.

Frank Brown, BPA, said that Cadmus calculated this number and it was universally used even though BPA staff may think that number is lower. He added that staff can use a different value when appropriate. Brown then said that the number might drop for a single-season program.

Jayaweera agreed that implementation will look different than planning estimates while seasonality and shared resources complicates issues.

Brown stated that Cadmus' \$150,000 estimate accounts for work from both BPA's and utility customers' staffs. Jayaweera likened this to the Council's need for a single assumption. Brown stated that the first-year cost barely affects the 20-year-levelized analysis and incentive costs matter more as the product ramps up and the penetration rate increases.

Nesbitt was in agreement with the presented set up except for some equipment maintenance costs missing from the O&M line. He asked about the proposed \$0 for equipment costs. Jayaweera explained the RTF findings and said the DRAC could model the \$1200 level-two charger or the zero-cost connectivity piece.

Nesbitt asked about software. Jayaweera said that's baked into O&M. Nesbitt suggested breaking the costs out even though he didn't know exact numbers.

Frew said she's seeing a \$400 difference between equipment with or without connectivity. Joan Wang, Cadmus, said she interpreted an incremental cost of about \$300 from the RTF work. Jayaweera said she will double check.

Nesbitt said the incentive depends on hours and restrictions but should go up if there are more interruptions or engagement. He said Idaho Power gets decent participation with \$15 incentive for AC cycling. Jayaweera said they assumed five, four-hour events per season as a proxy across all of the products. Nesbitt felt 40 hours was light for adequacy and they have 60. Brown said BPA designs demonstration projects for four-hour events 10 times a season.

Jayaweera asked if she should edit the workbook to four-hours events 10 times a season. Nesbitt called that reasonable.

Jayaweera then asked about the appropriate dollar per hour incentive. Nesbitt said a variable amount would be too small so they chose \$5 a month. Salmi Klotz said they don't see much peak charging in residential but didn't think \$20 would be enough unless it's per season.

Negash asked if this is time of use. Jayaweera answered no, it's called on. Negash said at Tacoma it's all about managed charging and they don't think about this product for DR. Jayaweera said that will be covered at a later date.

Salmi Klotz said \$20-\$25 a season is in line with other programs. Nesbitt said they pay \$15 a season for AC cycling.

Kyle Frankiewich, WA UTC, agreed that the interactive effects of an EV load control program versus load shifting will be interesting. He offered to circulate information around the UTC and try to get PSE to provide some ground truthing. Jayaweera said she is always looking for feedback.

Jayaweera asked about the correct percent transfer number. Negash asked if the 35% is the dispatch or if there's a year-round fixed incentive, noting that Tacoma is splitting their C&I program incentives and the variable one is 35%. Brown called this payment for the hassle-factor. He said he understands the CA protocol for other programs but wasn't sure how it would work for EVs.

Nesbitt said that no matter the program there's still customer outreach. He then said there might be a case where a customer wanted a fully charged car but there was an event. Nesbitt wasn't sure if 35% was the right number but felt it was closer than 75%.

Jayaweera moved to attrition rate. Nesbitt said the attrition rate is large, depending on marketing, and suggested 7%.

Jayaweera asked about using the 20% program participation number. There were no objections. Jayaweera then asked about event participation. Nesbitt asked if the percentage includes whether or not the car is present. Jayaweera answered that is tied into the peak load impact piece.

Negash noted that the numbers show 10% of 50% and thought the percentages should be smaller than a water heater's. Nesbitt felt that 10% seemed logical. Jayaweera asked if event participation should remain the same.

Frankiewich said .3KW seemed reasonable for peak load impact with the caveat that charging throughputs are increasing with each car model release. Jayaweera explained that the numbers are from a 10-year mix of vehicles and offered to compare numbers to a more recent mix of cars.

There were no comments about "Ramp Rates will be subject to EE measure adoption" or the 5-year ramp period assumption.

Water Heating

Heutte didn't think a per KW approach was necessary for O&M and felt the number of participant method made more sense. Jayaweera asked if the number is better represented as a staffing or per participant cost. Brown said it's related to how many water heaters are in a program and BPA converts everything to per house or per KW.

Nesbitt said Idaho Power prefers a fixed number plus a variable within that O&M.

Wang explained the basis for the PSE's \$7.50 cost spreads FTE across 20,000 participants. Heutte asked about \$12 per KW. Nesbitt and Wang said it's about capacity reduction at full penetration. Jayaweera said this adds up to \$12 in the summer and \$9 in the winter. Nesbitt recalled that \$12 summer only and \$26 for full year program used Cadmus's \$75,000 at full penetration estimate. Jayaweera said she would stick with the fixed \$75,000 as a proxy.

Brown explained that the \$340 for equipment costs includes marketing. Jayaweera corrected the number to \$330.

Jayaweera explained the complexities around Grid-Ready product. Brown felt that \$50 was ok. Nesbitt asked if the equipment cost includes installation. Jayaweera answered yes for the switch but grid-ready is different. Nesbitt then asked about operational software. Jayaweera said the number only includes labor and we should talk about DR management systems.

Brown said they use 25% Impact for water heaters and 35% for space heating. Brim said the ramp across all products is seven years. Brown felt marketing costs at \$50 was too high. Wang had no further inputs. Jayaweera changed the number to \$30.

Brown suggested 0.5 as a conservative summer Peak Load Impact number. Salmi Klotz said the .4 and .8 numbers are older and he needed to re-check. Jayaweera put in .5 as a placeholder for switch programs. Heutte said the report was probably from Minnesota and East Coast work. Brown said they did metering and there's a database behind the .55 number.

Salmi Klotz offered average multi-family numbers of .38 KW for HP water heaters and .5KW for electric resistance. He said winter was .6 and summer was .4 for electric resistance while HPs averaged .375, reminding the room that these are smaller units. Heutte asked what smaller means. Salmi Klotz said he'll have better, single-family numbers with larger units sent over. Jayaweera asked what kind of events the multi-family numbers represent. Salmi Klotz said the participants were not locked out and does some pre-heat based on usage schedule.

Heutte called the .35 peak impact number fine but said there wasn't enough data from single family ER homes and that number is likely to change. Heutte asked when pencils need to come down. Jayaweera answered March.

Jayaweera said she will use the .5 as a place holder. Heutte said this is a fast-moving market with a lot of upside.

Heutte suggested splitting single and multifamily to better capture HP KW impact. Jayaweera said that work is in the queue from PNNL to analyze the CTA-2045 study. Salmi Klotz said he had to check if there are any multifamily HPs.

Frew said that HP water heaters perform differently across heating zones and suggested factoring that in. Jayaweera pointed to RTF climate zone data and said she will keep the BPA data and leave spot for PGE data. Heutte urged that the DRAC not bake in wrong numbers and offered to look at CTA test data to get the best information.

Brown called the Program Participation number very low.

Jayaweera asked Wang about the 50% grid ready and 25% switch numbers. Wang didn't remember where the numbers came from but guessed they came from WA's new law. Jayaweera asked about the 10-year ramp rate for grid ready product. Brown argued that 25% for switch was too low for the region. Wang said the PSE number assumes the utility already decided to do the program and the 48% was the long-term participation rate. Jayaweera said this is what could be achieved.

BREAK

Jayaweera showed [Slide 74] from the RTF EV charger presentation to explain the cost difference between networked and non-networked product. Frew said the inefficient, non-networked numbers are a lot lower adding that this is a dynamic market. Heutte said the NW Energy Coalition EV expert will be in touch.

DR Management Systems

Brown said he assumes DR management systems are part of the \$75,000 O&M costs. Nesbitt asked about the cost of creating or buying the software. Brown said that's part of set up.

Jayaweera asked if the \$150k set up cost is sufficient to cover DR management systems. Nesbitt asked if that number includes personnel creating code internally explaining that takes time while external purchases get expensive. Frew said the \$150k depends on what you're trying to do and it may be enough to initiate DR events but not nearly enough to integrate it on systems.

Nesbitt said any DR system isn't useful until the load serving group can use it. Jayaweera asked if the costs are borne entirely by the DR program. Nesbitt said yes. Heutte pointed to PGE's SmartGrid report which talks about the complications of allocating costs in integrated systems.

Jayaweera said she will keep the numbers as they are for now and will reach out to PGE for more information about their management system. Nesbitt said there are companies that have the software but it's expensive. Jayaweera said that will still result in shared costs and allocation issues.

Brown said every DR program seems to be its own beast recalling that some require a software purchase and no funds for switches and controls while other require the opposite. He added that a third party brings their own proprietary system and you pay a bundled cost. He said this makes it hard to estimate the first two rows of the workbook. Jayaweera said the DRAC will revisit this.

Heutte reminded the room that this will not matter as much after scaling up, saying no one talks about the cost of controls for a gas plant.

Space Heating

Brown felt \$240 for switch is high and suggested \$230 and \$35 for space heater marketing. Brown also said BYOD people are more willing to participate in a program.

Frew said it's easy to override a thermostat but not a switch. Jayaweera agreed, pointing to the 70% event success number versus 94%.

Frew thought program participation for BYOD might be higher but not 50%. Frankiewich also guessed it would be higher, perhaps closer to 35%. Wang said a one-time incentive might raise participation. Jayaweera asked about adding a one-time incentive. Brown said that sounded okay. Jayaweera added a \$20 one-time incentive.

Brown said the 35% hassle factor was out of the California Protocol for space heating.

Jayaweera said this will be discussed further over the next six months. She promised to summarize the minutes and comments and send it out via email before the October meeting. Frew asked that Jayaweera include data needs for people to fill in. Brim thanked Jayaweera, calling the process transparent and informative.

Jayaweera closed the meeting at 3:45.

Attendees

Tina Jayaweera	NWPCC
John Ollis	NWPCC
Jennifer Light	NWPCC
Ahlmaz Negash	Tacoma Power
Tom Miller	BPA
Tim Johnson	BPA
Fred Heutte	NW Energy Coalition
James Vanden Bos	BPA
Tom Brim	BPA
Jason Salmi Klotz	PGE
Adam Schultz	ODOE
Tess Jordan	PGE
Suzanne Frew	Snohomish PUD
Bill Henry	D'joule

Attendees Via Webinar

Aaron Bush	Public Power Council
Blake Scherer	Benton PUD
Elizabeth Osborne	NWPCC
Frank Brown	BPA
Jeffery Moore	Green Lots
Joan Wang	Cadmus
Kyle Frankiewich	WA UTC
Quentin Nesbitt	Idaho Power
Nicolas Garcia	WPUDA

Will Price
Shirley Lindstrom
Teague Douglas
Torsten Kieper
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