Council Meeting
Portland, Oregon
January 11, 12 & 13, 2016

Monday, January 11, 2016

Council Chair Phil Rockefeller brought the meeting to order at 2:33 p.m. All Council Members were in attendance.

No Power Committee Meeting was convened.

Chair Rockefeller said that the two-hour session this afternoon would be devoted to a summary of public comments about the Draft Seventh Northwest Power Plan. "I've seen a number of editorial comments over the past several weeks and they generally have been quite positive," Member Rockefeller said. "It seems like we're on the right track."

1. Summary of public comment received.

Tom Eckman, staff power division director, summarized public comment as, "Yes, but …"

Council Members and staff have held eight public meetings with more than 300 attendees throughout the region, and they have received 470 comments. Also, nearly 150 individuals submitted written comments or offered letters in support to the comments provided by other organizations.

Eckman suggested going through the proposed responses to comments on the resource strategy on Wednesday, and on the technical and modeling assumptions now. Staff is using their best guess on where the Members would land on input assumptions. Eckman wanted to tie those down to see if they need to be modified. Tuesday they'll review Action Items, except for: 1. The resource Action Item on conservation; and 2. The resource Action Item on demand response. Those will be reviewed Wednesday.

Eckman shared an overview of comments on the overall strategy:

Nearly all of the organizations and individuals supported the Draft Plan's resource strategy's reliance on cost-effective energy efficiency and demand response.

- There was less agreement on the roles that natural gas generation and renewable resources should play.
- Utilities largely endorsed the need for additional, gas-fired generation to replace retiring coal plants.
- Environmental and renewable energy advocates, and many individuals, questioned the Draft Plan's finding regarding renewable resource development. They said that there is too much reliance on natural gas and not enough on renewables.

On the **resource strategy's finding on the need to develop regional capacity**, PNUCC agrees with the Draft Plan's finding that the region's power system needs additional capacity resources to meet winter peak demand. Further, the Draft Plan aligns with the last several PNUCC Northwest Regional Forecasts. This capacity shortfall is difficult to make up when energy resources with little peaking capability are added to the region's power system.

However, Bonneville wants to understand what this might mean for the agency's need to develop demand response. BPA's assessment does not indicate a need for winter-peaking resources. Eckman said Bonneville's raising the issue because the Draft Plan proposes using demand response to address hourly peaking problems. Bonneville says they have a sustained winter peaking problem, not a single-hour peaking problem. They can move hydro around to meet the hourly peaks. Other utilities don't have the luxury of the federal hydro system.

Ben Kujala, staff system analysis manager, explained that BPA has its own way of developing a load resource balance in their White Book. BPA doesn't see that they have a current winter need.

Member Rockefeller asked if that undercuts the need for demand response. Kujala replied that it might not make sense for BPA to do demand response as much as the rest of the region. Eckman added that there's a part of the Draft Plan that asks utilities to define their specific conditions and load resource balance situations, and to determine where demand response might fit in with their portfolios. Demand response might serve a different purpose for BPA. It's looking at it for wind integration, not winter capacity. It's using the same demand response terminology, but deploying it differently. One of the Action Items is for each utility do their own evaluation of how they could use demand response.

Kujala added that the biggest difference between BPA's assessment and the Council's is how much market they assume they have access to and how they treat their Tier 2 resources.

On the **role of energy efficiency in the resource strategy**, there was broad support for the reliance on cost-effective energy efficiency to meet load growth. However, there was some division on what the Plan's goal should be. BPA, the Public Power Council, PNUCC and public utilities called upon the Council to adopt a range of energy efficiency goals. PNUCC recommended a range from 1,300 to 1,450 aMW by 2021. It believes that a range will provide for the uncertainty of future load growth, gas and electricity price projections, and other factors that could affect the region's ability to acquire conservation.

On the other hand, the Northwest Energy Coalition and a broad range of advocacy organizations have called on the Council to adopt mid-point efficiency development from the social cost of carbon scenario as a minimum Plan goal — which would place the number closer to 1,400 aMW of efficiency. Bonneville and the utilities would use this goal to establish efficiency plans and budgets.

The Council Members discussed whether to set a fixed number or a range. Eckman pointed out that the region has surpassed energy efficiency goals for the past decade. In the Sixth Plan, there was a range — the Council had a goal 1,200 aMW that Bonneville had to budget for. "In the end, we're talking about 100 MW over six years, plus or minus," he said. "In terms of others in the region, they're not obligated to follow anything we do."

Council Member Tom Karier said he understands the interest in the lower part of the range. What about the upper? Eckman replied that the range goes up to 1,500 aMW. It's driven by the economic forecast, not so much by natural gas prices. It's more about how many houses in which you have to install new refrigerators.

On **the role of demand response in the resource strategy**, the comments were similar to those on energy efficiency. While the Draft Plan does not specify a numeric goal for acquiring demand response, it says that the region should be ready to develop the resource. There is general support for demand response as a way to meet capacity needs, but there are reservations about the region's ability to develop it.

Bonneville, PNUCC, Public Power Council, PNGC Power, and many public utilities support retaining the Draft Plan's current language. The Northwest Energy Coalition and a broad range of advocacy organizations would like a specified development goal of between 700 and 1,100 MW by 2021. They believe that without a measurable goal, utilities won't aggressively support demand response.

Council Member Bill Bradbury asked that if the Seventh Plan specifies a minimum goal of demand reserve capacity, would BPA have to work with member utilities to develop that ability? Eckman replied that it depends how you write it. "Generally speaking, if we have analysis that supports doing something, we're more likely to get it done versus saying it's 'legally obligated,'" he said.

Council Member Jennifer Anders said it's her understanding that BPA has suggested that demand response is not an obligation of theirs under the Power Act. John Shurts, staff general counsel, said that under the Act, demand response is more of a reserve than a resource. He said it is a tough question to figure out what is the reasonable, cost-effective thing to do, and that it's best not to try to resolve it legally at this point.

Regarding the **role of existing natural gas in the resource strategy**, the Northwest Energy Coalition, Sierra Club, Climate Solutions, Renewable Northwest, and multiple individuals commented that the Draft Plan relies too heavily on the increased use of both existing and new natural gas generation.

The Northwest Energy Coalition commented that investor-owned utilities are planning for 1,700 MW of new natural gas resources, which exceeds any natural gas resource development in the Draft Plan. They also raised the possibility of building stranded assets. Eckman said many commenters raised the issue of methane emissions from natural gas production, which they say could offset the benefits of natural gas compared to coal if evaluated over the entire fuel cycle.

On the other hand, PNUCC expressed concern that the Draft Plan sets unrealistically low expectations for the need for new, natural gas-fired generation in the coming six years. Most of this shortfall is due to the fact that the Northwest is being modeled as a single utility. Generation builds happen because regional utilities don't have equitable access to resources and transmission. Eckman added that the Draft Plan already states that individual conditions may vary and that individual utilities may have to build generation. However, PNUCC would like greater attention paid to the fact that some utilities will have to build generation to meet their customers' needs.

Eckman next shared comments on the topic of **regional resource utilization.** BPA commented that its sales to utilities in the region would reflect the preferences provided under the statute. PNUCC agreed, but indicated it is seeing new, thermal resource development and dispatches. That's because in practice, investor-owned utilities don't have unmitigated access to the hydrosystem and have to compete with other buyers, such as California, for surplus federal system power.

Council Member Pat Smith said he read BPA's comments, which pointed out that there's a regional preference on surplus power and they have to serve within region. But what if there's a difference in pricing and they're getting a lot more out of region? How does that work? Eckman replied that he would point to PNUCC's comments that IOUs have to compete with buyers in California. BPA says it prices its power at market rates, which could be set by California buyers, explained Eckman. He added that IOUs get back by using the Residential Exchange. The Public Power Council recommends that this section removed from the final Seventh Power Plan, saying that it is factually dubious and outside the purview of the Council.

Member Tom Karier sought clarification on the rate. In BPA's comments, regional utilities could request power sales, but a rate process determines it. It's not clear what that is. Eckman replied that Bonneville's Tier 2 is supposed to be set at a market rate. That's firm service. If it's a "jump ball" between in-region IOUs and out-of-region buyers, the in-region customers get preference.

On the **role of renewables in the resource strategy**, Northwest Energy Coalition, Climate Solutions, Sierra Club, Renewables Northwest, Washington Environmental Council, public interest organizations and multiple individuals commented that the Council's modeling of the value of the role of renewable resources over the 20-year planning horizon is flawed because the modeling:

- Does not recognize the ability of renewables to contribute significantly to winter and summer peak needs.
- Did not calculate the Associated System Capacity Contribution for renewable resources.
- Did not model scenarios in which transmission would be available for new Montana wind plants if Colstrip units 1 and 2 were closed.
- Did not model resources, such as geothermal, storage, energy market improvements, smart grid applications, and customer behavioral programs that could help integrate renewables.
- Used cost projections that are too high for solar PV beyond the Action Plan period.
- Did not model distributed solar photovoltaic resources, except under the Maximum Carbon Reduction Emerging Technology Scenario.

Council Member Bill Booth asked how to address the emotional support for renewables in the face of the need for firm resource availability.

"We are endeavoring to rectify some of the criticisms, and we're trying to configure some portfolios that might be more successful than what we've tested so far — or at least to elucidate what needs to be resolved," Eckman said. "For example, we know we have a problem with winter capacity with renewables, so we're looking at a conventional geothermal model that could generate year-round power. We're testing that to see if the model will take it. We need renewable resources with certain attributes, one of which is providing winter capacity. We focus on what works with the system. That's the best we can do given our charge. There's a limit on doing more of the same."

Next, Eckman discussed staff's proposed responses for updating the inputs to the RPM's scenario analysis

Multiple parties commented that the Draft Plan was based on **outdated natural gas and electricity market price forecasts**. Some parties also commented on what appeared to be differences between the load forecast used for the Regional Resource Adequacy Assessment and the Draft Plan. After consultation with the Natural Gas Advisory

Committee, the Council lowered long-term medium forecast by about $1 per mmBtu. The wholesale Electricity Market Price forecast also was updated, resulting in a $3-$4 dollar per MWh reduction in long-term prices in the medium forecast. The Council Members had no problem with these assumptions.

Another input assumption on **load forecast, natural gas and wholesale electricity prices** raised concerns that:

- Distributed solar PV installation was not included in plan;
- Load forecast did not account for increased use of Electric Vehicles (EVs); and
- Climate change impacts on future loads should be incorporated into the Plan.

The proposed staff response is that the Plan includes a range forecast of distributed solar PV installations and EV loads. In particular:

- Chapter 7 and Appendix E pages 38-39 discusses the Seventh Plan assumptions regarding distributed solar generation in the frozen efficiency load forecast; and
- Chapter 7 and Appendix E pages 56-60 discuss the Seventh Plan assumptions regarding distributed future EV loads that are included in the frozen efficiency load forecast.

“We need to clarify this to show we didn’t miss these things,” Eckman said. “Others may not agree with the level, but they are accounted for.”

He said that the high range of load forecast used in the RPM was designed to capture the potential impact of climate change, and that Appendix M and Action Items ANLYS-22 and COUN-11 describe the actions the Council will take to more fully investigate the impact of climate change on loads and resources.

Member Bradbury asked for a definition of “frozen efficiency load forecast.” Eckman replied that it assumes no additional energy-efficiency improvements beyond those embedded in new codes and standards that are already adopted, and actions they know that will take place because of stock turnover. It’s the baseline from which they subtract all the efficiency going forward.

Member Karier commented it should be specified earlier that a few hundred MW of distributed solar are part of the plan. “I think we’ve pushed it off as a detail, but it’s not to many people,” he said. “It’s renewable resource we see as expanding. I think we should explain that.”

Eckman said they can put it in the executive summary and in the state of the system chapter, and they can also describe EV assumptions there.

On the input assumptions on the **capacity value of conservation**, Eckman said that PNUCC, PPC, and several utilities expressed concerns about the reliability of estimated peak capacity impacts from energy efficiency. Some recommended using lower peak impacts from energy efficiency. Many support REG-1 to develop new, end-use information. There also was some concern about the cost and prioritization of this effort.

The proposed staff response is that they agree some data is old, which is why the Draft Plan includes Action Items REG-1, ANLYS-5, ANLYS-9, REG-5 and REG-6 to improve inputs and reporting for peak impacts. Eckman recommends that staff not change load shapes as no party submitted new data to support higher or lower impacts. He said that lowering the capacity impacts of energy efficiency is likely to increase the need for additional energy efficiency, demand response or other resources.

Member Smith asked that if staff did end-use studies, could they complete them by the midterm assessment? Eckman replied that it probably would be closer to the Eighth Plan. “It’s taken us 30 years to get as far as we are now,” he said.

Member Karier remarked that the Council could be over or under estimating, and asked if they should be more cautious and lower the capacity value. Eckman replied that lowering the capacity impacts of energy efficiency would likely increase the need for additional energy efficiency and demand response.

Eckman then explained input assumptions on **transmission and distribution investment deferral credits**. He said that when we don’t have load growth, we don’t have to expand the system. “That saves on investments,” he said. “You don’t have to build transmission, substations, poles and wires. When we cost out our resources, we take into account whether these resources are needed or not.”

PNUCC and several utilities identified differences between the Council and utility-specific estimates for the value of deferred T&D costs. PNUCC identified errors in the cost averaging used by the Council and they recommended an Action Item to develop new estimates for these values. Staff agreed and proposes to do so for the next Plan. For the time being, staff favors retaining the current assumptions because they don’t have other information. Eckman proposed inserting clarifying language in the Plan, which will explain the rationale for assigning economic value to the deferral of ongoing transmission and distribution investments.

Member Karier asked if we are double counting if we provide deferral credit, add in a resource and add a transmission resource to it. Eckman replied that they don't add it, they subtract it. Member Karier said that’s not what they thought we were doing. Eckman said that was correct. Kujala clarified that there are some costs for connecting to the transmission system. Member Karier said that on the transmission and distribution cost deferral issue, if there’s no load growth, then there’s much less value to defer. Eckman replied it depends upon why there’s no growth. If there’s no growth due to energy

efficiency, then the cost deferral is still real. Are we're willing to look at updated information if it exists? Eckman said, yes, but that it's a methodological issue to arrive at the number because you have to separate the investment in the T&D for ongoing system maintenance, and from those you have to make to expand the system, and it's usually not logged that way.

For **conservation supply curves,** multiple changes to supply curve input assumptions were identified and/or proposed. Staff proposes changing its assumption regarding how BPA funds its conservation programs, which it now expenses rather than capitalizes. It also will:

- Revise inputs to reflect error corrections and updates;
- Adjust the industrial energy management ramp rate;
- Adjust commercial lighting applicability factors;
- Add a new industrial lighting assessment; and
- Make about 40 other changes to specific measures or input data.

Staff also will increase the 20-year technical potential by approximately 40 aMW out of 5,200 aMW.

"We did a lot of housekeeping and didn't find much," Eckman said. "Forty changes for 40 aMW aren't a lot."

For input assumptions regarding **direct-application renewables**, the Oregon Solar Energy Industry Association and a few individuals expressed concern that the potential of direct-application renewables was not sufficiently evaluated in the plan. The proposed staff response is to direct staff to draft proposed amended language to Chapter 12 and Appendix G to expand the discussion of direct-application renewables.

For the **demand response supply curve input assumptions**, multiple comments were received regarding the cost data used to develop the assessment of demand response potential. A commenter provided data on the cost of installing space-heating demand response controls and programmable communicating thermostats. Staff made some modifications to increase the cost of one measure and decrease the cost of another.

Solar PV cost input assumptions were reviewed, and commenters thought that the Draft Plan's current solar PV costs and cost forecast assumptions over the next six years are reasonable. However, several parties (NWEC, OSEIA, Renewables Northwest and individuals) expressed concern that the long-term cost forecast for solar PV is still too high. In response, solar costs have been updated with the recent Investment Tax Credit Extension, which lowers near-term costs. In addition, a range of solar costs was developed, and a low-cost solar option was made available in some RPM scenarios. The solar costs for the reference plants are well within range of most future cost projections — indicating that the estimates are reasonable.

For **reserves held for balancing and flexibility**, Bonneville commented that the final analysis should include regional balancing reserves, not just those for its balancing area. Bonneville also noted that its balancing reserves are lower than what was in the Draft Plan: 900/1100 MW for INC/DEC. Bonneville changed it to 400 MW INC and 300 MW DEC for Spring, and 900 MW for both INC and DEC for the rest of the year. These new values should be reflected in the final analysis

Member Karier observed that they seem like very large adjustments. Eckman replied that they are, and that will mean a lot. “When we talk on Wednesday you’ll see that there are implications,” he said. “We had to do this first because it is based on everything we own. It’s not an inconsequential change.”

On the issue of **wood smoke**, the WUTC stated that the Plan should quantify health benefits; as well as the financial value of emissions reductions, especially particulates, for conservation measures that result in reduced wood burning, and other activities that generate particulate emissions.

Shurts said that the WUTC wants the Council to try and quantify the benefits. The RTF took a serious look at it. Health benefits are one aspect, but trying to monetize it is something else. He said they understand the issue, but quantifying it isn’t something they’re proposing to do in the Seventh Plan. The RTF was divided on how many resources should be spent researching this issue and staff has decided to use its current assumptions. Eckman said there is a sidebar on this in the energy-efficiency section. It needs to be expanded in Chapter 19 about why we’re deferring.

Member Karier wanted to understand the consequences. If it isn’t quantified, does it change the Plan’s energy-efficiency targets? Does it limit what utilities can do and get credit for because it falls off the energy-efficiency list? Eckman said it doesn't change the energy-efficiency targets. It could limit utilities where there’s a lot of wood heat. The analysis does provide for reducing wood heat concerning the cost of wood, but not surrounding emissions reductions.

Charlie Grist, staff manager of conservation resources, said that if you’re going to do this analysis, you do it for every measure that might change the wood heat situation. That’s a lot of measures, beyond the scope of what we can do.

On the input assumption, **accounting of methane emissions for natural gas and coal**, the Council heard that it did not sufficiently take into account the adverse climate effects of methane (CH4) emissions from activities related to natural gas-fired generation. The proposed staff response is that:

- The Council’s primary method for considering environmental effects is to reflect regulatory compliance costs in the analysis;

- A regulatory scheme exists for carbon emissions;
- Proposals for regulating methane emissions for new facilities are being considered, but not for existing facilities that are the source of most of the emissions. Therefore, the Council must address methane emissions in a qualitative way;
- The RPM includes accounting for CO_2 emissions, but not CH_4;
- Staff will provide additional discussion of the methane emissions accounting related to the power system, its complexities and subtleties, and potential future compliance costs.

Eckman said that they account for gas emissions at the tailpipe, but not its transportation to the generator. They also don't account for getting coal to the generator. If they account for the entire fuel cycle for natural gas, they would have to do it for coal. The state of the art is that there's great uncertainty on what those levels should be. They don't think we can do a fair accounting of fugitive emissions for methane and coal, so they're addressing it, but not monetizing it. They will change the narrative, but not much else, he said.

Member Bradbury asked where methane releases occur. Steve Simmons, staff senior economic analyst, said It's in the production and transmission of the gas. Newer wells have fewer methane emissions than old wells because they're required to separate out the hydrocarbons. In the past they have been vented. Most of the leaks are coming from a few pieces of equipment. By replacing those, you can capture a lot of emissions.

Member Karier wanted to know if this lends itself to an Action Item. Leaks of wells should be fixed and there are bigger policy issues of using natural gas in our power system. We don't want methane released, which complicates climate change. The Power Plan could explore how we could contribute to that policy discussion.

Council Member Henry Lorenzen asked, "Who would be the target for implementing this Action Plan? Karier said the owners of the infrastructure, and the Council could communicate that to the owners and the federal regulators.

"Are we getting far afield of our power plan?" Lorenzen asked.

Member Karier said, "It enhances our portfolio if there's a reduction in this fugitive gas that supplies it. We don't directly affect it, but we don't need to ignore it either."

Member Rockefeller asked if we have natural gas production in our region. Simmons replied that we don't — two-thirds is imported from Canada, and the rest from Wyoming and Colorado.

Shurts said that if there were regulation, those costs would be captured. "It does need to be regulated," he said. "But it's a problem with existing wells. Once you address it, it can be solved. But we think it's within the range of the natural gas forecast we already have." He added that we don't have legal authority over it.

Council Member Jim Yost said, “Let BPA to take care of it. We ask them to do a lot of other unnecessary things. It’s an air quality issue. We’ve done a good job on the power plan. We have a lot of things we need to work on and try to fix. This isn’t one of them. We need to do the narrative and explain the situation, and let it go. We don't need another Action Item to write a nasty gram to EPA to get it fixed.”

Moving on the modeling analysis, on the topic of **environmental compliance for existing coal plants,** NWEC and Sierra Club questioned whether the Council sufficiently accounted for all the of the regulatory compliance costs (in particular capital costs) for existing coal generation in the RPM. These organizations also stated that the Council’s footprint of resources should include the out-of-region coal plants that are paid for by some PNW ratepayers. The Council’s analysis does include the capital cost of environmental compliance of existing coal plants. Council’s analysis considers existing resources that are impacted by new resource decisions within the region. There’s no need to model them because the Plan has no impact on them, and their operation doesn’t impact the resource strategy. PacifiCorp owns several plants in Utah and Nevada. They aren’t dispatched to meet Northwest loads.

Member Rockefeller asked staff to expand the narrative to explain why we’re not going to include these out-of-region plants.

Regarding the **Recent Adequacy Assessment and the Draft Seventh Plan,** PNUCC recommends that the final Plan acknowledge the results of the Resource Adequacy work and how they differ from Seventh Plan findings. Idaho Power submitted similar comments. Staff acknowledges that they are different and are based on the sixth plan. Therefore, they come to different conclusions. Staff proposes revising the language in Chapter 11 to reflect changes between Sixth and Seventh Plan assumptions that affect the adequacy assessment.

Member Karier observed that the adequacy assessment had about 1,000 MW of needed capacity, and the Seventh Plan had 700 – 1,100 MW of demand response and capacity. Both were looking at capacity resources past 2021-2022. Were they that different?

John Fazio, staff senior power systems analyst, said that the difference is the shape of hourly loads. For resource adequacy assessment, they use load forecasts from a short-term model, which looks at history to project forward. For the Plan, they use a long-term model, which is an end-use model. It includes the impact of standards and programs that will happen. Another factor is energy efficiency. When they did a comparison of 2020 loads, the LOLP itself was very close, but there was a shift in when the problems occurred. In the short term, there were more winter problems than summer. In the long term, they diverge more and the summer problems become greater.

A repeat of an earlier issue is the **Low Expectation for Natural Gas Fired Generation**. PNUCC is concerned that the draft Plan may be setting an unrealistically low expectation for the need for new natural gas-fired generation in the next six years. Staff recommends that additional discussion be added to Chapters 1, 3 and 15 to reflect the differences in the assessment of regional versus individual utility resource development needs.

Eckman explained that it's the issue of the Plan modeling the region as one utility. Staff agrees it will have the minimum amount of generation required because of the resource sharing. It's where everyone is one big, happy family. Staff will add narrative again explaining it's the best model, because the system doesn't have complete liquidity to get it from one place to someplace else. It's likely that there will be additional investments to build new resources. Whether it's of the magnitude the utilities in the region see for natural gas development compared to the Plan is an open issue. "We know that it's higher than we estimate, but whether it's as high as they say is another matter," he said. "We see low probability by 2021, and according to their IRPs, they say 1,700 MW by 2021. We'll talk about that on Wednesday. Every utility will have its own, unique needs, but that's a big difference right now."

Member Rockefeller asked if there's any place to capture acting as a happy family. Eckman said they state that there are benefits, but there is no solution for making that happen.

Member Rockefeller wondered if by emphasizing that utilities can choose to do their own approach, are we giving them a blank check to do what they want in in their IRPs? Where do we counterweight that?

Member Smith said that it would make a difference to various regulators in making their decisions.

Member Booth said that in his experience, on-the-ground data is better than modeling data. He thinks there is value to a regional model if everyone is one big happy family. Down the road, he said he's not sure the Council needs to take the position that because we're a modeling outfit, that we won't take real-world data. In a case where you have utilities tasked with keeping the lights on, if they're able and competent, he doesn't know why the Council wouldn't use that data. Don't discount what utilities say they have to do to keep the lights on.

Eckman said they'll use any data that people make available.

Member Yost said that if every utility had the same generating resources, demographics, etc., we could identify things that could be constant in the region. Things in Idaho and Montana are different than in Seattle and Portland. It's going to be impossible for us to do this, we have to get as close as we can. I think we've done a better job in this Plan than the Sixth Plan in identifying that.

“I like idea of demand response the more I think about it,” he said. “I recommend some curtailment on the west side.”

Member Lorenzen observed that one of the challenges is that we have 20 Balancing Authorities.

Eckman said that there is an Action Item aimed at the Council to review the models and to determine what fits them forward.

Member Karier said, “I don’t want to end on a note that there’s no value in a regionwide analysis. Before modeling, we ended up building a bunch of nuclear plants that weren’t necessary. Individual planning can underestimate the needs in the region as well. We do have markets and a sophisticated transmission system, so decisions made independently sometimes fall afoul of larger markets. There’s a lot of value in regionwide models.”

Eckman said he wouldn’t dismantle the architecture we have now. It just can’t be taken as a prescription for everyone.

Member Karier concluded that as the resources are built, wholesale market prices might gravitate toward that level, and it might defer a power plant, or make it not cost effective due to wholesale prices.

On **low thermal dispatch from a “single utility” approach**, PNUCC notes that the existing thermal generation in the RPM appears to be under-dispatched, saying it creates unrealistic, low carbon dioxide emissions because of the single-utility perspective in the models. While staff agrees that a regional dispatch may not capture market inefficiencies that lead to higher carbon emissions, the difference is only about 5 to 10 percent, not double as has been claimed.

In accounting for **WECC-wide carbon emissions due to changes in regional exports**, PNUCC recommends that the Plan should discuss the impacts of reduced regional exports by potentially increasing carbon dioxide emissions in neighboring regions. Eckman said the Plan would acknowledge this. In the short run, it would be thermal, and in the long run, the region’s hydro might be competing with solar in California, Eckman said.

In comments about an **incomplete calculation of the capacity value of renewable resources**, Eckman said that they are rectifying the capacity value of renewables. They didn’t have estimates for solar and wind as they did for energy efficiency and combustion turbines. They will review what they found on Wednesday and the estimates will be included. Their capacity is estimated on a quarterly basis to show the seasonal differences.

On the **North Valmy retirement** issue, Idaho Power believes that the assumption in the Plan to shut down the two, North Valmy coal-fired units in 2025 is overly restrictive. The owners have not determined a closure date. Staff will acknowledge this in the narrative and

leave the 2025 retirement date as referenced in the owners' IRPs as a modeling assumption. The Plan isn't doing anything to prepare for their retirement.

In comments to **diversify renewable resource options for the RPM**, several commenters, including NWEC, Renewables Northwest and Sierra Club, raised concern over the lack of diversity in the renewable resource options in RPM — especially for Montana wind with potential coal plant retirements, and geothermal and solar in other locations. Staff added a west-side solar resource and will more clearly detail Montana wind's contributions.

On comments regarding **new and existing nuclear generating resources**, staff proposes to revise the Plan's narrative to reflect updates to cost estimates and the environmental effects of nuclear generation. The Council can determine whether to review Columbia Generating Station economics post-Seventh Plan, but it's not in the Plan because it's an existing resource. Small Modular Reactors (SMRs) are not commercially available.

Generating Resources Odds & Ends:

- There was a request to include more clarity regarding battery cost estimates. Staff will clarify language in Chapter 13, Appendix I, and double check cost calculations.

- There was a concern with providing the RPM with only an aero derivative combustion turbine for peaking service, rather than less-expensive frame technology. Gas peaking options were discussed throughout the modeling process — aero technology was settled on as the most representative in terms of needs, cost and performance.

- There was a concern that solar was considered "highly speculative." Solar was considered a "primary" resource and was included in all modeling. Solar + Battery Energy Storage System was considered a long-term resource and was included in the Emerging Technology Scenario. Staff will revise the narrative to clarify.

On whether Demand Response (DR) is a Capacity Resource, BPA commented that demand response falls within the category of "reserves," and does not fall within the meaning of 'resource' as defined in Section 3 (19) of the Northwest Power Act. The Council believes that demand response provides reserves, and it also provides peaking capacity like a capacity resource — therefore, demand response is a resource in the sense of its functions. It's not necessary at this time to settle this as a legal point.

Member Bradbury said that he support that effort. "I think it's important to not put us in a position where demand response is NOT a part of what we should be doing," he said.

Regarding the use of **January Adequacy Reserve Margin (ARM) to determine the need for resource builds to meet adequacy standards**, the Draft Plan's analysis only used

winter quarter (i.e., January) capacity requirements to determine whether and when new resources are required. The Council's loss of load probability (LOLP) metric measures resource need across all seasons. Therefore, the RPM's adequacy assessments should consider potential shortfalls in all seasons. Staff agrees that model analysis should consider shortfalls in all quarters.

Eckman said that staff is looking at taking the adequacy metric annual and measuring it quarter-by-quarter. There are summer and winter problems in the region. Fazio explained that it requires the Council to change its adequacy standard to a seasonal standard, which is an Action Item, and a recommendation to the Council.

The **use of single-hour peak load and 10-hour, sustained hydro capability to establish ARM** appears inconsistent. Bonneville noted that the ARM for capacity is calculated using single-hour peak load, while the hydro resources available to meet the single hour peak is based on its 10-hour sustained peaking capability. Bonneville recommended that the single-hour peak hydro capability should be also used. Staff proposes maintaining the current analytical assumptions. Fazio said that the reason they don't do a single-hour, hydro peaking capacity is because they can't sustain it over time. It would be an arbitrarily high amount. Most curtailments are 6-10 hours.

Regarding an **analysis of the removal of the Lower Snake River Dams**, the Council received multiple comments from environmental organizations and individuals requesting that it run a dam removal scenario similar to the one done for Sixth Plan. The scenario modeled for the draft concerning the planned loss of a large, non-carbon resource provides sufficient direction as to what a resulting resource strategy would look like. Modeling the removal of these dams in particular would affect only certain details not captured in the scenario modeled, particularly the details of the hydro changes. The narrative in Chapter 3 and 15 describing the scenarios tested can be modified to highlight the differences between the analysis done for the Sixth and Seventh Plans without modeling another scenario.

In addition, the Council received multiple comments from environmental organizations and individuals requesting that it **independently analyze the economic viability of the continued operation of the lower Snake River Dams**. **Staff argues that, b**ecause this analysis would not affect the new resource analysis, resource scenarios, or resource strategy, which are the focus of the plan, it is not a Power Plan issue. The Power Plan has no element or effect relating to the viability of existing resources, whether to continue operating them or whether to remove them.

Shurts remarked that if the region wants this taken up, they could do it outside of the plan. Staff doesn't have the expertise on it.

Member Bradbury observed that there would be a 1,000 MW unidentified loss or a planned loss. Fazio said that the four Lower Snake River Dams account for 900 MW, and the Columbia Generating Station is about 1,100 MW.

Eckman added that a major event could produce this outcome without pointing to WHY. “We don’t get into whether they’re economic to retain in the fleet or not,” Eckman said. “We don’t have engineers on staff to estimate whether moving all that earth is good or bad. We just look at the economics of replacing that load.”

Regarding the **value of the hydrosystem/AEERPS/F&W program**, NW RiverPartners and Northwest PPC recommended that the Council include more in the Plan to recognize the value of the hydro system, and its contribution to addressing needs of fish and wildlife. It wants the Plan to continue to assess the fish and wildlife program’s effects on adequate, efficient, economic, and reliable power supply; and to hold the fish and wildlife program accountable to existing budgets — even if new fish and wildlife priorities are to be funded. Staff will review and revise the narrative describing the hydrosystem, the role of fish and wildlife measures and how they’re implemented. There won’t be any new analysis, but staff will look at the narrative.

There were comments to preserve and strengthen **protected areas**, especially given interest in new hydro development. Staff responded that protected areas designations remain unchanged, and that protected areas provisions are reviewed in the Fish and Wildlife Program. There is no need or benefit to reviewing them again in power plan, since the Act deliberately places the Fish and Wildlife Program ahead of Power Plan development.

Member Bradbury said he still has a concern about the leaking methane, and he wants to know if we’ll come back it. Eckman assured him that they would. Shurts added that staff received a lot of comments on that topic. He said that they can get back to things and they go through the language. He said they captured a lot of comments, but not all of them. Council Members will be able to see them all.

Shurts reminded Members that the Council is no longer taking public comment. But the Council can reopen the process to take public comment if needed.

Adjourned at 5:00 p.m.

Tuesday, January 12, 2016

Council Chair Phil Rockefeller brought the meeting to order at 1:29 p.m. All Council Members were in attendance.

Reports from Fish and Wildlife, Power and Public Affairs committee chairs

Fish and Wildlife Committee

Member Bradbury, Fish and Wildlife Committee Chair, said that the meeting began with Patty O’Toole, program implementation manager, and other staff members, who provided

an update of an update of the Council's research plan. The long-awaited ISAB/ISRB report on critical uncertainties should be ready later this month. They will work to get a report from the science bodies in February. After public comment, they will revise the research plan. They are uncertain of the timeline, but they should be able to complete it by the end of this year. It should ultimately lead to the implementation of research projects.

They now have a letter on a science review of predator management ready to send to the Council and the ISAB oversight board. They condensed the questions to one — a common predation metric. Members will hear about it today or at the next Council meeting. Mark Fritch, staff project implementation manager, updated the committee on funding request that had been reviewed by Budget Oversight Group. The proposals totaled $212,520, and the committee and Council will see those in February.

There was a presentation on the Oregon Hatchery Research Center by Dr. David Nokes of Oregon State University. He's leading a study on the olfactory imprinting of fish embryos. They imprint on water that they have incubated in, so they can go back to a specific area. They don't imprint well on well-water, only water from streams. Fish respond to the amino acids in the water. So work is being done to add the chemicals to the water to get the fish to return to hatcheries.

Further studies are being done on how fish find ocean environments through magnetic fields. Fish use their smell to find their way home, as well as electromagnetic systems to know where they are. The committee will look into taking a tour of the Oregon Hatchery Research Center.

The committee heard a presentation on the Council's emerging priorities. Member Booth's Operations and Maintenance Subcommittee is working on a review of screens. The RFP has been reissued and responses are due this Friday. There will be 10 site visits, and they hope to finish the review by the end of this year. Researchers are truing up the fish screen database to address the most grievous needs first.

Member Anders and the Cost-Saving Subcommittee met twice to discuss Council methodology and how BPA will address it. The Council will use objective criteria and CB fish to identify savings. They will try not to look at projects involving policy considerations, just objective criteria. The hatchery assessment review by the ISRP should come out tomorrow.

The Power Committee did not meet this month.

Public Affairs

Member Anders, chair of the Public Affairs Committee, reported that the committee did not meet last month and would not meeting today.

2. Distribution and Use of Cold Water Refuges in the Willamette River

Dr. Stan Gregory, Oregon State University and a member of the ISAB, said they have been studying the mainstem of the Willamette River since 1988. He introduced David Hulse (on the phone) of the University of Oregon. Since 2008, they noticed that there were habitats in the river that were colder than the mainstem. They have been sampling native and non-native fish community from Eugene to the mouth of the river in Portland. He reviewed data on the number of species they would get on one kilometer of the river. The number of native species decreases from Eugene to the Portland area. Consistently in 2011-2013, they were observing 18-19 native species in one kilometer of habitat. Of the fish captured, 93 percent were native. It's a real strength in Oregon's rivers, he said. They do see larger proportion nonnative in warmer waters, such as bass, perch and bullheads. The Willamette River gets fairly warm. Between 2008 and 2015, we exceed the temperature standard every year. This year was hot. The temperature near Harrisburg got up to 23-24 degrees Celsius. In Portland, it was 26 degrees Celsius last summer, so there were major thermal stresses.

Debra Sturdevant of the Water Quality Section of the Oregon Department of Environmental Quality Oregon wanted to develop a scientific basis for revising the temperature standard for Oregon. Chinook in the Yakima River system would tend to hold in cold-water habitats to chill their bodies down and then dash through warm water habitats. Therefore, there was a need to protect cold-water refuges.

Gregory discussed how to identify cold-water habitats. In 2010, the Meyer Memorial Trust and OWEB funded the study of thermal patterns in the mainstem from Eugene to Portland. They looked into more than 100 soughs, side channels and tributary mouths. Every quarter of a mile, they performed a vertical profile to determine the temperature from top to bottom. They found places where the mainstem would be 21 degrees and in the sloughs it would be 10 degrees. But fish also need oxygen.

There was a detailed discussion of river water, friction and its impact on temperature. Seventy percent of the sloughs have colder water than mainstem. Forty percent have water colder than the mainstem, meeting the definition of cold-water refugia.

Gregory discussed the profile of cold-water refuges 2011-2015. He said, "We know that scientists can sense temperature, but do fish know it? We put sensors into a fish. We caught that fish three times. It stayed between 13-16 degrees. These fish know where they should be."

Gregory said that between 2008 and 2015, they sampled more than 80 sloughs along the mainstem. Seventy-two percent were colder than the mainstem, and 40 percent were more than 2 degrees colder than the maximum mainstream temperature. The majority of the cold-water sloughs had conductivity values that were similar to the mainstem. Dissolved oxygen concentrations can be low in some sloughs. Most of these colder sloughs also

contained adequate concentrations of dissolved oxygen to support native fish at the depths where cold water was detected.

When they sampled these waters, they found that fish communities differed substantially between sloughs with cold water and warm water habitats:

- Numbers of native fish species were greater than non-native species in cold-water habitats, but numbers of non-native species exceeded numbers of native species in warm water habitats.
- Abundances of native fish were greater than non-native fish in cold-water habitats, but the abundance of non-native fish exceeded the abundance of native fish in warm water habitats.
- Native fish made up more than 60 percent of the individuals captured in cold-water sloughs, but non-native fish comprised more than 85 percent of the fish captured in warm water sloughs.
- Salmonids were approximately 10 times more abundant in cold-water sloughs than in warm water sloughs.
- Chinook juveniles were found in two of the 10 cold-water sloughs and were not observed in warm water sloughs.

He then explained the process of implanting temperature data loggers in fish in the Willamette River to determine the thermal environment used by cutthroat and rainbow trout.

“The protection of cold-water habitats is important,” Gregory said. “The river is changing because of human-caused changes in sediment supply and water. We have reduced floods by 30-40 percent. What was a 1-in-10 year flood event is now a 1-in-100 event.”

He said there has been a 60 percent reduction in sediment supply. “We have changed the Willamette River,” he said. “These cold-water habitats are formed by a dynamic river, with gravel bars and floodplains that move. When we cut down the sediment supply and floods, we allow the sediment to settle in and we lose the cold-water habitat. It’s the floods that are restoring the habitat along the Willamette River.”

Member Bradbury asked what the river conditions were like in Portland. Gregory replied that they do have Portland data. But they can’t sample fish if the water temperature is over 18 degrees. Their permit prevents that. Most of the cold-water habitat is in the Upper Willamette River.

Member Karier asked if they ever put a radio tag on the fish to see if they dash from cold-water refuge to cold-water refuge. Gregory answered that they have put radios in cutthroat trout. When they released them, 49 percent went to cold water in less than a week. The problem is that the fish have to be large enough to pack a radio. If they’re in a thermally stressed environment, it’s harder to evaluate them.

Member Karier said that this research shows the importance of cold water in survival, and asked if he had other suggestions.

Gregory said there have been some suggestions for creating cold-water habitats. A gravel company worked with them to create a cold-water slough, but it quickly filled in with sediments and it became a hot-water habitat. These cold-water habitats are formed by river process, so what is needed is a naturally changing river to the best degree possible. They also have looked into pumping well water, but there has to be enough oxygen in it.

They wondered about making their cold-water refugia map publicly available. But wondered if it would end up being a fishing guide to get trout in the middle of the summer. “We decided that the positives outweighed the negatives,” Gregory said. “Good fishermen know this stuff already.”

Member Rockefeller asked Gregory if he has developed a rule of thumb for when temperature results in a lethal situation.

Gregory replied that he relies on laboratory studies. There’s a volume of information on temperature, duration and available food supply, he said. We tried to evaluate the temperature at which we find the fish.

Rockefeller asked about the temperature range for Chinook. Gregory said it is about 12-22 degrees Celsius. They tend to find them in warmer water than the cutthroat.

3. Briefing on the Biological Opinion on Potential EPA Approval of Oregon Water Quality Standards.

Mary Lou Soscia, Columbia River coordinator of the Environmental Protection Agency’s Region 10 office, said that EPA has been long concerned about water temperature in the Columbia River Basin. They started a water quality plan in the 1990s. They worked on that for a number of years, but were never able to complete it. Had it been completed, she said it would have identified protecting cold-water refugia as one of the key implementation actions.

John Palmer, EPA’s senior policy advisor for the Office of Water and Watersheds, talked about on the biological opinion that was worked on with NOAA. It represented a great chance for people to come together. Last year was the warmest year in Oregon. There is climate change and we’ll see temperature increases. He told the Council they want to help with its Fish and Wildlife Program.

Palmer reviewed the Columbia River Cold Water Refugia (CWR) Plan, starting with the Clean Water Act. The regulatory context is that states adopt Water Quality Standards (WQS), such as water temperature, which are used for point source permits, listing of impaired waters, and watershed cleanup plans (TMDLs). EPA approves or disapproves

state WQS. That action is subject to ESA Section 7. There was a lot of legal activity between 2003 and 2015. They recently completed the consultation. Oregon adopted new temperature WQS in 2003. The numeric criteria for rivers and streams based in fish use are 12C, 16C, 18C and 20C. The issue had to do with the 20C, for the Oregon Columbia and Lower Willamette River temperatures.

Palmer said that the Cold Water Refugia (CWR) narrative criteria "must have CWR that's sufficiently distributed, so that salmon and steelhead can migrate without significant adverse effects from higher temperatures elsewhere in the water body." NMFS said in the BiOp, since we had 10 years to implement the standard, the narrative wasn't functioning properly. So there was jeopardy for steelhead, Chinook, sockeye and killer whales.

Rather than try to fix the standard, they decided that the implementation was the problem. Therefore, the RPA states that:

- The EPA shall develop a Columbia River CWR Plan;
- Oregon DEQ shall develop a Willamette River CWR Plan;
- EPA shall work with NMFS, Columbia River Federal Caucus, and the NWPCC to align this work with FCRPS BiOp and Columbia River Fish and Wildlife Program; and
- Columbia and Willamette CWR plans due by November 2018. That's three years from when the BiOp was completed.

Palmer said that when they negotiated this with NMFS, they wanted to create linkages with programs that were already in place.

CR CWR Plan area's six elements to accomplish in the next three years are:

- Characterize current spatial and temporal CWR
- Characterize current salmon and steelhead use of CWR
- Identify potential locations to restore CWR
- Assess whether current CWR is sufficient to meet Oregon's narrative criteria
- Characterize the additional CWR needed
- Identify and prioritize actions to protect, restore, or enhance CWR

Luckily we're not starting from scratch, he said. A lot of work has been done by the University of Idaho and funded by the Army Corps of Engineers. Palmer explained the research on how fish are using the cold-water refugia. Almost all fish are using it. Fall Chinook doesn't use it as extensively as its threshold is higher. He then discussed fish behaviors seeking out cold-water refugia in different rivers.

He said they looked at 109 tributaries and the deltas provide cold-water refugia opportunities. It's a start in mapping out the cold-water refugia that fish will use. They will generate analysis for a number of locations.

Palmer said the upcoming work includes:

- Monitoring additional tributary temperatures;
- Characterizing tributary plumes/confluence areas;
- Performing steelhead/salmon radio-tag studies;
- Developing models to compare thermal risks of fish that use and don't use CWR and help determine sufficiency of CWR in the Columbia River (comparing the risks of fish using the cold-water refugia with those that don't. The ones that do use it are less successful getting to their destination because they're probably being caught. The hypothesis is that if it weren't for the fishing, it would be beneficial, but that has to be studied);
- Assessing cumulative available CWR and fish migration rates; and
- Identifying and prioritizing actions to protect and restore CWR areas.

Member Rockefeller remarked that it seems that they know where they are and that they could take steps to protect them. "Dr. Gregory had a more dynamic view that the river can create and destroy refugia," he said. "How do you expect to stabilize sites for the long term if they're subject to the dynamics of the river?"

Palmer replied that they're looking at where the tributaries come into the river. That's a more consistent profile. That's different than the complexity of the floodplain. Where there's an area that's cold, they want to keep them cold or make them colder, he said. Dr. Gregory agreed that there are differences in sloughs and tributary junctions, and not as much in the floodplain.

Member Karier asked about the fishing hypothesis. Is it a significant difference and what can be done about that? Palmer said that there was a paper showing a 5-8 percent difference in the success rate due to fishing. "At the EPA, that isn't our job," he said. They create the environmental conditions to protect the cold water. It requires more research.

Member Booth said he had the same questions. It's impossible not to fast forward and think about what the regulatory enforcement structure might be due to this new BiOp. He imagined that it could affect fishing, but that's not EPA's arena. In tributaries, you have shade issues, riparian management and other factors. It could impact how landowners manage the riparian zone on their property. On the mainstem, you're focusing on the mouth of the stream. "Do you intend to get into pooling effect of hydroelectric facilities?" he asked. "How far do you see this moving? You haven't discussed that at all. Do you see this BiOp affecting hydro operations?"

Palmer said he didn't know. Initially they will look at tributary influences. They'll look at variability in the reservoirs. Whether they get to something related to the operation of the FCRPS to enhance an opportunity for cooler water, they don't know yet. When they look at opportunities, they'll cast a broad net.

Member Booth asked Palmer if they had appropriations set for this. Palmer said they did not. In the BiOp's language, it says to partner with NWPPC and other agencies.

Member Rockefeller pointed out that the presentation centered on Oregon, but the river also is in Washington. "You didn't mention Washington as a partners in this effort," he said. "Is this only in Oregon or are you coordinating with the State of Washington as well?" Palmer replied they are going to be coordinating with the State of Washington from the water quality and fisheries aspects. "This is an Oregon standard, but it applies to the river itself, so we're looking at tributaries coming in from both sides," Palmer said.

Member Rockefeller asked if this effort has a bearing on the BiOp that will relate to Oregon obligations under the ESA. What is the context for this work, or will it be relevant to the FCRPS BiOp opinion?

Palmer said not directly. "The FCRPS BiOp had conditions to develop a CWR report, so we're building off that and taking it to the next level," he said.

Soscia said that when she was chair of the Columbia River federal caucus last year, she was working on NOAAA on the BiOp during a high-temperature year. The caucus did prioritize these efforts with the intention of seeing what opportunities are in the FCRPS BiOp and this BiOp to work together. There never was an intention to affect or direct the FCRPS BiOp.

DEQ's Deb Sturdevant agreed to develop a CWR plan under the BiOp, and will take the lead on the lower 50 miles of the Willamette River, which also is designated as a migration corridor. She said they aren't as far ahead as the EPA is in terms of pulling data together. They have one year under the BiOp to develop a scope of work, and then three years to complete the plan. They are looking for opportunities to collaborate with other agencies and academic institutions interested in this issue. They need to rely on available data for the first round. Fortunately there is a lot of interest and expertise. They will be pulling together a team, compiling data and answering the same questions that came out of the BiOp. They want to know where there are refugia, how to restore it, and how the fish are using it.

Member Booth asked if the speakers were familiar with Water Trust. There was some work done in Idaho at Lemhi. There are opportunities where initially, you're going to find some resistance. People who own the property feel like they should be able to manage it. If you can get into these communities, and get to know them, and the organizations, it will help. When they see that there's a way to maintain their lifestyle, soon everyone's excited about the salmon coming back. And it can be done. If you don't just come in with regulations and enforcement, you can make a big difference. It took us 15 years.

4. Continuation of discussion of public comment and potential changes to the Action Plan

Eckman led the presentation on the Draft Plan's Action Plan, which is Chapter Four. Two Action Items received the most comment are RES-1 (conservation goal) and RES4 (development of demand response). They will be discussed tomorrow.

Charlie Grist, staff manager of conservation resources, discussed the energy-efficiency Action Items.

RES-2 – Evaluate cost-effectiveness of measures using methodology outlined in plan.

Several utilities commented that the language should assure that this methodology is meant to be applied generically, with the parameters determined by the individual utilities. Staff agrees and proposes clarifying the text to indicate that the methodology applies regionwide, but input assumptions may vary by utility.

Member Karier said that the Council's methodology was to use an RPM model which individual utilities don't. So are utilities not using the same methodology? Grist replied that they could use the methodology for cost effectiveness of measures, independent of the RPM. It is used to derive the overall level of conservation, including the capacity contribution. The utility can take the methodology for cost effectiveness and apply it with their various inputs.

The Council Members agreed with the Action Plan Item.

BPA-6 – EE implementation model review.

BPA-6 Assesses Bonneville's current energy efficiency implementation model and compares it to other program implementation approaches. Three parties (PPC, NRU and ICNU) suggested this item was out of scope for the Power Plan. Three other parties (Bonneville, NWEC and Tacoma) indicated support. Staff recommends no change.

Member Rockefeller asked why the three parties thought it was out of scope. Grist said it's a "you're not the boss of me" approach. Shurts said it's an issue between the program, the resources you want to acquire and how you implement it. Eckman said that ultimately Bonneville decides that, but we can suggest they study alternative ways to implement it.

Member Bradbury said he didn't understand comparing to other approaches. Eckman said the current design takes a certain amount of money and allocates it on the loads customer have. It's an equity model, you get so much based on load. There are others that might be served by a different design.

The Council Members agreed with the Action Plan Item.

MCS-1 Ensure All Cost-Effective Measures Are Acquired

This model conservation standard Action Item addresses “hard-to-reach” markets. It ensures that all-cost effective measures are acquired. Multiple parties expressed support for ensuring that hard-to-reach (HTR) populations have access to energy-efficiency programs. Idaho Power expressed concern about the additional reporting requirements of this Action Item. Staff proposes no change to this Action Item, as it has been extensively discuss by Power Committee members.

The Council Members agreed with the Action Plan Item, with a “no” vote from Member Yost.

Member Yost said, “I’ve spent the better part of 12 months disagreeing with part of the intent of the hard-to-reach concept because of the additional burden on utilities. We were able to reach an agreement to modify this so that (the utilities) are not going out digging for more information, but rather are collating information if they could get it. So they don’t have to research demographics or their customers, if they’re poor or whatever. They’ll just report data from agencies suited to that task. I agree we ask too much of utilities sometimes, but this is about as reasonable as it will get because I can’t get seven of you to change your mind.”

Scope of NEEA’s Business Plan

NEEA provided comment on REG-2, where they highlighted the named Action Items that were not in NEEA’s current business plan. The proposed response from staff is that NEEA will ultimately determine its business plan. Staff can revise recommendations in REG-2 to be implemented by Bonneville and utilities directly if NEEA’s board rejects those actions. Staff proposes retaining the Action Item.

Member Yost said that this could be another 7-1 vote. This group doesn’t manage NEEA, he said. They have a budget and do a lot of good things. Of the items that we list that they should do were in their work plan. Their board said they’re spending a lot of money and shouldn’t be doing things. But our Power Plan is in addition to their Action Plan that we’re asking them to do, and it might not be in their budget. It’s an easy out to sit back in a policy position to ask them to do things.

“I think it’s a wrong approach for us to take. We should prioritize what they can do in their budget, and then be patient. Why do you want to keep adding it on to Bonneville? Why not just provide them with things in their budget to do in the next five or six years? I don’t like this approach. I think staff gets glad-handing because they don’t have to pay for it. What if the Council had to pay for it? Would you still be supporting it? We’re supposed to be statesmen and planners here. We need to quit passing the buck.”

Grist said it might clarify to talk about things not in scope. There are five things in scope and four on the cusp.

Member Booth asked if NEEA said no to some of these things.

Grist said that some are in the Plan and they'll go to their board.

Member Booth asked why not leave it the way it is? See what NEEA can do, but don't dump it on someone else.

Grist mentioned Action Item RES-1 as being in scope, which is to develop end-use load shapes. It calls on BPA, the Council and NEEA to do it. Staff asked NEEA to convene the group together to put the work plan together. The board already has adopted the first stage of that one.

Another is worth discussing: asking NEEA to provide market transformation support for demand response where it overlaps with energy efficiency items in their portfolio. NEEEA said they're not doing demand response.

Another was about water saving measures, and another is a best practice guide for new and emerging industries, such as data centers. It's not in NEEA's plan, but they do have an emerging technologies area. So they're not hugely out of scope.

Member Rockefeller asked that if those are in scope, what isn't in scope?

Grist said:

- Develop strategies to coordinate energy efficiency planning within the region;
- Develop a regional work plan to focus on emerging technologies to help ensure adoption;
- Conduct regional specific stock assessments;
- Monitor and track code compliance in buildings; and
- Understanding and doing the analysis of the impact of codes and standards on load forecasting.

Bonneville is doing this work and wants to move it to NEEA. If not, then BPA will continue doing them.

Eckman said that the discussions they had is that it's a regional activity, not just a Bonneville-area activity. Codes and standards impact the region.

Member Lorenzen asked if there is a middle ground, something not so directive. If NEEA rejects, BPA will review.

Member Smith said it seems like reasonable ground. The first two are pretty big items. The NEEA study and market transformation are pretty big items. This would allow them to assess. Those two jumped out as priorities for the Council and for the region. This provides more flexibility on what fallback is.

Member Karier suggests asking NEEA to work with the Council to develop a strategy to get it done. But the water one is in a different category. The other three need to be done. If not though NEEA, we'll figure out how to get it done.

Staff will revise the language accordingly.

Action Plan ANLYS-6 and ANLYS-8 Energy Efficiency Non-Energy Impacts

ANLYS-6 and ANLYS-8 identify and analyze significant non-energy impacts. Multiple parties commented on items related to improving the process to quantify non-energy impacts, such as water savings. NWEC called for more comprehensive analysis and better documentation. Several parties cautioned that prioritizing water savings is out of scope, and others are concerned about spending too much analytical time on non-energy impacts at the expense of other analysis. Staff proposes revising ANLYS-6 to focus on the non-energy impacts of water savings, and to conduct research to better understand those benefits, rather than to prioritize adoption and track impacts.

ANLYS-8 is more of a process recommendation. Staff proposes housing this effort at the RTF policy advisory committee and for the RTF to figure out a process for prioritizing non-energy efforts.

Shurts said another aspect of this is the analysis of the wood smoke issue. It fit within this box as well.

"When we're in a drought situation, water is one of the most significant non-energy impacts that there are," Grist said.

Member Karier said that from the comments, it seems like they were bristling at idea of prioritizing measures that saved water, and that ratepayers would be putting effort into saving water for uses other than electricity. "I understand that," he said. "We really want to say that we encourage utilities to coordinate with their counterparts in saving water so that the effort is streamlined and efficient, and can bring together multiple incentives for electricity and water to be more effective. That would be number one. What you have here is different. Seems like we do measure it currently, we include it in the cost effective calculation. We should continue to do that. Is there a need to change what we're doing?"

Grist said, yes, it could be improved. They need better data on wastewater treatment.

Member Karier said it still doesn't obligate utilities to spend more on energy savings, just on the tests. He wants to encourage the collaboration.

Eckman said they would have redlined versions at the February webinar.

Lorenzen asked if we are thinking about using less irrigation water. He said it's a slippery slope, and he wonders about it detracting from the enormously important work they have to do on the hydrosystem.

Eckman said that the members of the RTF PAC are the funders of that. They can choose to limit their involvement. With respect to data development, there is a limited set of measures that impact use and consumption, which also impact electricity use. It's not global. We have clothes washers, dishwashers, showerheads that require potable water, which requires treatment after. That can be energy intensive. It's a pretty narrow band of measures.

Member Yost said the wise way was to put water into ANLYS-8, and they can decide what's going on. Eckman said that's what the Council is doing.

Member Smith said that, with the wood burning issue they dealt with, there's not a consensus at RTF PAC. They are reluctant to go deep into their budget. They're pretty cautious about this, given the amount of time they already put in to the wood-burning issue.

Regional Forum on Business Models and Rate Design

Some members of the Northwest Energy Efficiency Leadership group recommend the Council convene a regional forum to explore alternative business models and rate designs, including how fixed and variable charges are allocated under stable or declining load growth. The forum should include regulators, IOUs and POUs, and should underscore the need to put energy efficiency on the same plane as other utility resource investments.

The proposed response is that the Council should consider adding the proposed action after a discussion of scope and the expected role of the Council. Staff recommends focusing on a new Action Item to work with a NEEL subgroup. The results of the NEEL November meeting can form a starting point for issues to address.

Member Karier is co-chair of this effort with Bonneville and PacifiCorp. He explained that it is to have a forum on the future of the business model for utilities, how that's changing and how that fits in with utilities. The Council would be the ideal entity to lead this discussion. It would be a good idea to scope it out and engage in it slowly with a broad group of utilities. There's a lot of angst in the region with distributed solar generation, integration of renewables, portfolio standards and what's happening in California.

Eckman we could have an Action Item or it could be just direction to staff

Member Lorenzen said he strongly supports this.

Member Yost said he thinks the action has merit. The question is, should be in the Seventh Plan. Member Karier replied that we have a whole section of Council actions. It's a sign of responsiveness to many utilities that signed on to doing it.

Eckman said we could take a cut at it, bring something back and the Council can decide how you want to play it.

Member Rockefeller said that it's odd we'd have a section asking ourselves to do something.

Remaining Action Items: Demand Response

COUN-1– Establishes a Demand Response Advisory Committee.

Multiple parties recommended that the scope of the Demand Response Advisory Committee be expanded to include distributed standby generation, distributed energy storage, transactive energy, and other specific "smart grid" or "grid edge" technologies — in addition to focusing on the near term barriers to deployment of demand response and estimating its future potential. Staff said that the specific scope of the Demand Response Advisory Committee will be established by the Council when the committee's charter is drafted. Staff revised Plan language to indicate that Council should consider these technologies when determining committee scope.

There was general support among Council Members to do this. Kujala said the comments from others were along the lines of "yes, and you should do more."

RES-4 – Expand Regional Demand Response Infrastructure

Bonneville recommended exploring how current energy efficiency programs can be leveraged to expand demand response infrastructure. Staff agrees and will revise RES-4 to Recognize the potential for how leveraging energy-efficiency programs could expand capacity to deploy demand response.

RES-5 – Demand Response Market Transformation

NEEA commented that this is not currently covered under their business plan and that adding demand response features to current, end-use market transformation activities could likely be incorporated without large resource impacts.

Staff will change the language to reflect the other NEEA proposal.

BPA-3 – Continue Efforts to Establish Demand Response Capability
Bonneville stated that it is premature to develop rules for the acquisition of demand response. The Washington Energy Office commented that this Action Item should include a timeline. Staff proposes retaining the Action Item since BPA is already engaged in multiple

pilot programs that support development of its ability to develop demand response capability.

Eckman said he would prefer not to write down how they're going to develop demand response. He heard from others that putting infrastructure together requires you have contracts and offerings in-place.

Kujala said there isn't a target in the draft. The idea was that the utilities should develop their own approach for the level of cost-effective demand response to develop. BPA said it's too early to determine what level is cost effective. We believe the findings in the Plan steers us toward that, and it's hard to back off from that.

Member Rockefeller asked that when BPA said it's premature, was it interpreted as being opposed?

Kujala said BPA wanted to see the rules for acquisition softened. They agree that the structure is moving in that direction, but they want to see that phrase edited. That also would involve the Action Items for considering cost-effective efficiency and demand response.

Member Karier observed that there's no timeline on it.

Member Rockefeller asked why can't we respect their sense of timing on this? And say they can move forward at the appropriate time? Member Karier said it's already lacking in teeth. There's no timeline, so I think we leave it as it is.

Member Yost said, "I like it the way it is. All we're asking BPA to do is to find a utility willing to cut off power to customers and develop a program to do that. Pick out certain blocks in Portland and Seattle. It's only for a few hours a year … in the winter. If it affects their heat, they'll get warm later."

"Think about what we're asking BPA to do," he continued, "to work with other utilities to turn off power to their customers for a fee. It's up to the utilities to do. It will be on the west side. But it's a different task at best to ask someone to develop a program to turn the lights off to somebody. They need time to develop it."

The computer says we can do demand response quickly and cheaply. I disagree with both hypotheses. But we have it in our Action Plan."

Member Karier said, "I'd be more skeptical if Idaho hasn't been leading the region in demand response, and doing it effectively, efficiently and at low cost."

Member Yost said, "It took us a long time to build the program – seven years. It's very expensive. We went to war with people the region to get the price reduced." He said it was

a summer experience, not winter, and it was irrigation. The crops didn't care if they were watered between 10 and11 in the a.m. versus 4 and 5 in the p.m. He said if you want DR on the east side, they could help. "It took a long time to develop with the PUC and it's not easy, and it's not cheap. It's the most expensive resource that we have. I'm not going to object any longer to having this Action Item in here. But in two or three years, when we do midterm or eighth, think about the time line we asked, how easy it would be, and how much we're going to get, I think we have expectations that are greater. It's been successful elsewhere, but not in the Northwest with the resource loads we have for the utilities."

The Council consensus was to approve it.

Remaining Action Items: Modeling and Data Development

BPA-7 Operating Reserve Studies

Bonneville should perform an analysis of its operating reserve requirements. ICNU stated that these studies lie outside the Council's planning responsibility. PPC, PGP and SnoPUD stated these Action Items should be removed. WUTC supported this Action Item. Staff believes that deleting this Action Item may lead to insufficient data for required elements of the Eighth Plan. The Power Act explicitly requires the Plan to include analysis of planning and operating reserve requirements for BPA and the region. BPA agreed it should be done.

The Council consensus was to approve it.

BPA-8 Oversupply Mitigation

Bonneville should continue to evaluate methods for reducing or mitigating regional generation oversupply conditions. Bonneville commented that oversupply protocol has not been used since 2012, and stated this Action Item is covered by current activities and recommends deleting the Action Item. The proposed staff response is that Bonneville's comments do not address the objective of this Action Item, which requests that it work with its customers to create incentives to address oversupply. Staff proposes retaining the Action Item language as is. It's an item proposed by Member Lorenzen.

The Council consensus was to approve it.

BPA-5, REG-3 and REG-4 – Action Items for Obtaining Information

Bonneville suggests the Council review Action Items (BPA-5, REG-3 and REG-4) and other recommended actions in the Draft Plan that are purely driven by the need to acquire data. Bonneville feels there are more appropriate opportunities and forums to determine how to acquire such data. Staff believes that the data requested in these Action Items are necessary for the performance of the Council's functions. Staff recommends these data be made public in existing public processes at Bonneville. If this option is unavailable, the

Council could pursue official data requests under the Power Act and facilitate publication of data. Staff proposes retaining the existing Action Item language as necessary for the Council function.

Kujala said that BPA 5 was about conservation benefits and financial analysis information disclosure. Member Lorenzen requested the Action Item.

The Council consensus was to approve it.

Review Analytical Methods

Smart Grid NW, NWEC, WUTC, and PGE commented that demand response potential for provision of ancillary services is underrepresented and undervalued in the Seventh Plan.

Staff says that Chapter 14 acknowledges that the use of demand response to provide ancillary services are not explicitly simulated in the RPM, so the potential value of demand response in this area is not captured in the Draft Plan's analysis. Staff recommends revising Action Item ANLYS-20 to recognize the need to address ancillary services in future plans. Staff proposes revising the last sentence of ANLYS-20 to read: "This review will focus on changing regional power system conditions such as capacity constraints, balancing and flexibility constraints, and transmission limitations to better address these issues in future power plans."

Eckman said this is performed after every Plan. They go through their models and data analysis, and question what they didn't do and what they wish they had.

Member Bradbury asked, what is a revision of ancillary services? Kujala said it's the ability to move up and down in load and generation. It's referred to as increasing generation reserves, but there are a lot of characteristics to it.

Member Karier said the Council has focused its response of demand response development. BPA has been running pilots on demand response, primarily for these ancillary services, and the Council might want to have a broader look at it. There was a detailed discussion about the issue.

There was no Council consensus.

Adjourned at 4:15 p.m.

Council Meeting
Wednesday January 12, 2016

Chairman Rockefeller called the meeting to order at 9:01 a.m.

5. Continued discussion of Action Items for the Seventh Plan

Tom Eckman and Ben Kujala offered an explanation of the following Action Items:

Additional Action Item — Low Carbon Grid Study

There was a request by Renewable Northwest, Climate Solutions, NWEC, Sierra Club and several individuals to participate in a low-carbon grid study. It would replicate one performed in California, which identified a research study that eliminated all carbon from its power system. The study was done by third parties, including the National Renewable Lab, GE and others. However, the Council's Power Plan has a different objective, which is to determine a least-cost resource strategy for the region, while taking into account environmental attributes. But zero carbon is not the goal of the Plan or the Act.

Staff ran two scenarios that reduced carbon significantly — the emerging technology scenario and the maximum carbon reduction scenario. The emerging technology scenario they ran could get to zero carbon if those technologies emerged.

Council participation in such a study could enhance data available for use in the Eighth Plan, but it also could require significant staff effort.

The Council guidance could be 1) Direct staff to develop an Action Item, or 2) Do not add Action Item.

Eckman said that the value proposition for staff is getting the data that might emanate from the study, not necessarily relative to the task of the Power Plan.

Member Smith said the Power Committee hasn't met since this came in. He said they don't know a lot about the California precedent or how much work this would be. It's a pretty major change in focus from the Power Act's central purpose, which are low-cost resources. He said he has concerns.

Member Lorenzen said that they don't have enough information to make a wise decision. Even if it's not in the Power Plan, they're not prohibited from doing it later. "So why clutter the Power Plan with things we don't need to do?" he asked.

Member Bradbury said he's in favor of a third option. Put some staff time into looking so it so we know what the scope of it is.

Eckman asked if the Members wanted an Action Item to investigate the potential for the study, or include it in a work plan going forward. The parties who commented just wanted some staff participation.

Member Rockefeller asked if we know that there will be such a study. Eckman replied no, it's prospective. In talking with Renewables Northwest, the sense is that if the study were included in the Power Plan, it's more likely to get off the ground.

Member Rockefeller said, "It sounds like we don't have to make a decision until we're invited, or until we hear there's going to be such a study."

Council Members agreed on no Action Item.

Impacts of Sub-hourly Markets on Balancing and Flexibility

ODOE recommends that the Plan include an Action Item for the Council to further develop analysis methodology regarding impacts of sub-hourly markets on balancing and flexibility. Additional comments were received that recommended enhancing the Council's modeling capability of variable generation to support integration studies. Kujala said he believes this is adequately covered by ANLYS-20, and proposes not including an additional Action Item.

Member Karier remarked that as we study reserves and balancing, we would have to think about the role of markets. Kujala replied that this is likely work we'll have to do, but it's covered for now.

Council Members agreed on no Action Item.

RES-6 Expand Renewable Generation Options

Eckman explained that when they did modeling, one finding is that that solar PV and geothermal showed up as more viable resource option than additional wind in the Gorge. They felt they should enumerate that finding embedded in the Action Plan. As utilities review their compliance options for RPS, they should look at solar and geothermal as more compatible than additional wind development. Tacoma, however, read it as too prescriptive. There's a statement in that Action Plan that each utility should look at its own needs to determine what is needed. We still want to leave that language in there. We will have to raise that sentence that it's a local decision in each IRP, but to please consider this.

Council Members agreed to make language changes proposed by staff to Action Item

F&W-1 Effect of Renewable Resource and Transmission Development on Wildlife

F&W-1 calls for the Council to investigate further the effects of renewable resource development and associated transmission on wildlife. The Washington Department of Fish & Wildlife enthusiastically supported this Action Item and seeks further Council commitment. No other agencies or tribes commented. Utility organizations do not support it, stating that this is not a role for the Council.

Staff proposes that Council Members consider three options:

1. Retain the Action Plan commitment to investigate this issue further;
2. Remove this item, as not a priority action by the Council in next few years; or
3. Modify the Action Plan item to promise less of a commitment to investigate, and yet retain the idea that we will help investigate this to the degree others are interested.

Staff recommends Option 3, but views Option 2 as equally viable. Staff also proposes retaining the discussion of the effects and highlight issues in Chapter 19 and Appendix I; and to add language that Council is not in a position to call for or enforce a mitigation program, a version of a protected areas program, or funding for a comprehensive assessment of renewable resource and transmission development.

Shurts said that this has been a concern raised in Washington. In the 2014 Fish & Wildlife Program, Washington Department of Fish & Wildlife and the Tribes expressed concerns about the cumulative effect of developing renewable resources and associated transmission, and that not enough was being done on their cumulative effects on wildlife.

Shurts said that staff promised them we'd look at it in the Draft. The most we could do in the Draft is say that we'll look at this further. We got a note back from them saying that this something they see as a priority. They want a commitment from us to do something. Other than that, we've had no comment from anyone else. Utilities don't think this is a priority, that this is something we should not get into, and that land management agencies can address it.

Shurts said what we can't do is write in a mitigation program or a funding of a comprehensive assessment. We're at a point of removing it altogether, leaving it in or retaining it and just saying we'll see where this goes. I'm looking at Washington Council Members, as it's more of an issue with them.

Member Karier said he thought there was a compromise and that we'd look into it.

Shurts said what we can do is investigate this further, talk with the agencies and find out what is the problem. Is mitigation not happening? Are the cumulative effects not getting studied? There's probably not a solution at the Council and Power Plan. It's more about the Council providing a forum to find out what the objections are. They want to see it targeted at protected areas, there would be an assessment of where resources are a threat and could guide development in a different direction. But these are siting issues.

Member Karier said he thought this language was adequate and was conditioned on learning something, and perhaps doing something in the next Plan.

Member Lorenzen said it opens up a Pandora's Box. "There are significant local land usage issues, generation and associated transmission, and refugia impacts," he said. "I don't

know if we should go down this road. I favor a slimmed-down approach, and give the staff the flexibility to look at it."

Member Rockefeller expressed interest in the third option to see if there's a broader slate of parties interested.

Shurts said he could bring a revised version to look at it.

Member Karier said that WDF&W told him that at each one of these location is a wildlife impact: golden eagles, raptors, birds and bats. When you look at collectively, it's a large number. Someone should be taking a look at it over the region. Perhaps we could help, not take the lead.

Shurts agreed with the description. He said they asked for data and didn't get it before the draft. It's one reason they are a little bit leery. The Power Division has enough to do, Fish and Wildlife has enough to do, so it would fall on Shurts to do the work.

Member Booth said if they consider this, he has an interest in looking at it from a state sovereignty debate. Especially if the proposal is some type of regional regulatory scheme that would look at siting in the region, and alter the current scheme that gives sovereignty to the federal government and states.

Member Karier said a new regulatory scheme wouldn't work; it would be just to look at the impacts that could support those local processes. I think the scope is limited to that. It might be that collecting information is sufficient.

Member Booth said it could be a lot of work to ask from staff if the Council is not going to do anything with it.

Member Smith said he likes options 2 and 3, and suggests bringing those back to help us flush it out more.

Shurts said that one attraction is our protected areas program for new hydro. They have mapped areas to protect and have some enforcement there. They have no approach under renewable resource or transmission. Every single siting decision nobody objects to, but it's the cumulative impact that people aren't taking into account.

Staff will return with proposed option language changes for Council review.

Eckman asked the member if they have any comments on Action Items that haven't been heard yet.

Member Karier said he had a comment on an existing policy scenario. Since we started this, the Clean Power Plan has become final and wasn't in the "existing policy." Is the Clean Power Plan part of it and, if not, can we legitimately call it the "existing policy?"

Eckman said it depends how you want to describe "existing policy." Since the existing policy appears to meet the Clean Power Plan's emission goals, it doesn't seem like we have to redefine the policy. At the regional level we're okay, but the states might do something different.

"But we do fall a little short, because the Clean Power Plan will affect states," Member Karier said. "We don't know exactly how. And it will be different than our existing policy most likely."

"What got us there were the existing policies that already have designated certain coal plants for retirement, and existing policy of building energy efficiency and demand response," Eckman replied. "There's nothing incremental that has to be done to get to the Clean Power Plan level. These are decisions made by utilities already. I don't know what we would change or configure except for the current policy."

"All the resources we model are consistent with the new policy," Shurts said.

"But we should acknowledge that the Clean Power Plan would precipitate the closure of certain existing plants, and that could change the existing scenario," Member Karier said.

Eckman offered to bring a narrative that caveats what add state action might take place for compliance. "We don't know what that is because we're not modeling state compliance," he said. Kujala said that it's unclear what approach each state will take at this point.

Member Rockefeller said that from a regional point of view, there's plenty of headroom, but for individual states not necessarily.

Member Karier said that in many places in the Plan, we state that the region is compliant with the Clean Power Plan. "Wherever we say that we need to caveat that individual states may not be, and that the region may not opt for a regional plan."

Shurts said they didn't get to all the comments on the draft, and will get to more as we go through revisions. We didn't bring all 480 comments to you, Eckman added.

Discussion of proposed updates to the Plan Resource Strategy

Eckman reviewed the following updates:

Revised Analysis Reflects Input and Modeling Changes

Staff revised the RPM logic to test for resource adequacy quarterly, rather than only in winter quarter. In addition, they:

- Developed quarterly Adequacy Reserve Margins (ARMs)
- Developed quarterly Associated System Capacity Contribution factors (ASCC) for CCCTs, energy efficiency, wind and solar PV; and
- Assigned aero derivative gas-fired turbines and geothermal resources the ASCC for CCCTs.

Revised natural gas price, external electricity market price and load forecasts

These are the changes discussed previously, with no large, narrative impacts. The range has shifted down by a dollar from where it started in the draft. It goes up and down seasonally. Staff:

- Updated conservation and demand response supply curves;
- Reduced the RPS requirements to reflect RPS based on sales rather than utility load;
- Added new solar PV and geothermal resources into the mode; and
- Updated maximum potential for other renewable resources and solar Resource costs to reflect changes in Investment Tax Credits (ITC).

Representation of existing resource capability

To provide a representation of existing resource capability, staff:

- Revised critical hydro representation to a low percentile (2.5 percent) representation of historic quarterly hydro;
- Reduced regional existing resource availability to account for estimated total region balancing and flexibility reserves (we had Bonneville's reserves in the draft, now we have the rest of the region's included); and
- Updated historical hydro dispatch to reflect revised regional "INC" and "DEC" reserves.

Eckman and Kujala provided a **terminology primer** for the discussion ahead:

INC – represents a type of reserves on the power system that involves either increasing generation output or decreasing load on the system.
DEC – represents a type of reserves on the power system that involves either decreasing generation output or increasing load on the system.
ARM – Adequacy Reserve Margin
ASCC – Associated System Capacity Contribution

Member Karier asked, isn't the ARM the capacity needed, and the ASCC is what resources provide?

Yes, Kujala replied. When we put in the increased balancing reserves, this was our net peaking. We have reserves for Idaho Power on their system, for PacifiCorp on their system, etc., but it does reduce our peaking capability for the hydrosystem. This has implications for build out, Eckman said.

Eckman discussed the **Types of Adequacy.** The RPM examines adequacy for both energy and capacity. The ASCC estimates the relationship between energy and capacity based on the capabilities of the system resource portfolio. The RPM builds resources when either energy or capacity or both are in deficit. ASCC is only for new resources.

Eckman explained that if the wind is generating, you could store water for peak demand. When you add 100 MW to the system of those resources, it may produce more than 100 MW in capability because they can store water in the hydro system.

Member Bradbury remarked that the Columbia River hydrosystem doesn't have that much storage. Eckman replied that it's week-to-week, not year-to-year. Kujala said it depends on the water condition too.

This is why we had to go to quarters, Eckman added.

Fazio said this is needed because in the early drafts, we saw the RPM overbuilding resources. In the GENESYS model, there's a dynamic relationship between resources and hydro, it simulates that relationship between the two. In the RPM, that interaction is not there. In order to let the RPM know what if you add a particular resource, it has this extra capacity contribution, which allows us to bring the adequacy of the RPM results so we're not overbuilding anymore.

Karier said it seems like we're using averages over time. In a dry year, you're more likely to use that storage. In a wet year, you don't need it. Are we missing something?

Fazio said no, it's related to the ARM. We're testing to see if the RPM will produce adequate supplies. The main thing is that we're checking for things that meet our adequacy standard.

The **Adequacy Reserve Margin** coordinates between GENESYS and RPM to identify the need for rate-based resources to maintain reliability. It should not be compared to Planning Reserve Margin. The ARMs may be zero or negative when relying on in-region Independent Power Producers or external markets, and still meet adequacy standards.

Calculating quarterly ARMs: ARMs are based on the Council's annual adequacy standard of maximum 5 percent Loss of Load Probability (LOLP). That means there is a 5 percent or less probability of taking emergency action to maintain reliability. The draft used a Q1 ARM to represent annual load-resource balance requirements, because that's when

the region has its peak load. Quarterly ARMs and seasonal hydro are required to represent the seasonal load-resource balance to meet quarterly LOLP targets.

Eckman said that you have a 5 percent LOLP and be perfectly adequate in the winter, and miss a bunch in the summer and still only total 5 percent. With a quarter-by-quarter basis, you have to have more fidelity on what that number is to reach. Fazio added that you couldn't just aim for a 5 percent quarterly target. What if your curtailments come in different quarters?

Action Item COUN-3 calls for a review of adequacy metric.

Member Anders observed that Q4 statistics show a higher percentage of the time that the LOLP is higher. Kujala replied yes, we're willing to risk more in the winter than in the summer.

Member Karier said that's an assumption you've made. Eckman replied that it was derived by monthly curtailments and a lot of studies.

Kujala said we're assuming that we're maintaining a similar adequacy level, as it exists today. You could decide to shift your risk appetite between winter and summer. But we didn't have a way of setting up how that would change. Thus, the Action Item that has the RACC coming up with several options to consider about the adequacy metric, Fazio said.

Kujala said they have a lot of Action Items the RACC is going to be looking at.

Member Booth said if you're looking at firm power, firm resources, you can't have a plant in the first quarter and then it goes off. It's there for the entire year. Fazio said it's true for all resources unless it's demand response or hydro.

Associate System Capacity Contribution

The Associated System Capacity Contribution (ASCC) represents the contribution of a resource to system capacity, e.g., reflects the ability of the hydro system to store water. In the Draft plan, energy efficiency and Combined Cycle Gas Turbines (CCGT) had ASCCs based on Q1 peak contribution. The proposed Final Plan uses ASCCs based on quarterly LOLP.

There was a detailed discussion on the Renewable Resource Associated System Capacity Contribution for the Draft and Final Plan.

Impacts

- The Final shows more energy surplus than the Draft. This is due primarily to updated lower-load forecasts. The seasonal ARMs show Q4 and Q1 have a similar energy adequacy situation.

- The Final shows less capacity surplus than the Draft. While the expected peak load decreased, the peak hydro capability also decreased based on updated INC and DEC reserves.
- Seasonal ARMs and corresponding hydro capacity result in potential capacity needs for all quarters except Q2.

In summary, staff went from looking only at winter problems to year-round problems.

Eckman said they have spent a lot of time looking at the inputs to the analysis. They have run seven scenarios, these four were discussed:

Revised scenarios:

1. Existing Policy
2. Existing Policy with No Demand Response
3. Existing Policy with Increased Reliance on External Markets
4. Social Cost of Carbon – Mid-Range

These are the principal scenarios with distinguishing characteristics that determine the components of the portfolio and what the timing is. There is one with maximum carbon reduction, which retires all coal plants by 2025. It might be on the table, but there's not a big consensus about it. The Social Cost of Carbon – Mid Range assumes some restrictions in addition to the Clean Power Plan.

The updated scenario analysis addresses three primary questions:

- Should the Resource Strategy's regional conservation goal and demand response development be modified?
    - Public comment was divided on whether the Plan should express its conservation goal as a range or single value.
    - Public comment was divided on whether the Plan should have a goal for a demand response.

- Should the Resource Strategy's findings be modified regarding the need for new natural gas generation development?
    - Public comment was divided on whether the Plan found too little need for gas resource development or adequately conveyed the lack of need. PNUCC thinks we missed because of "one utility" modeling.

- Should the Resource Strategy's findings on the benefits of Renewable Resource development be revised?
    - Public comment stated that the Draft Plan's analysis of renewable resources did not reflect accurate value and system impacts.

The factors driving the pace of conservation development are:

- The need for capacity drives conservation development.
- Assumptions about Demand Response development drive conservation development.
- Assumptions about the availability and cost of external market resources "in extreme weather and poor water" conditions" drives conservation development.
- Assumptions about further CO_2 emissions reduction policies drive conservation development.

Eckman showed a graph showing the probability of energy efficiency by 2021. Updated scenario analysis shows little change in conservation development patterns across scenarios compared to the Draft Plan. "If we take demand response out of it, we need to build 100 MW of energy efficiency," he said. There's a tradeoff of 100 MW. They also beef up external market purchase and reduce exports.

The factors driving the pace of demand response development:

- Need for capacity.
- Assumptions about conservation development – a tradeoff between the two resources.
- Assumptions about the availability and cost of external market resources "in extreme weather and poor water conditions.
- Assumptions about further CO_2 emissions reduction policies.

The same factors about how much energy efficiency to build influences the amount of demand response. The updated scenario analysis shows a material change in demand response development through 2021.

There was a detailed discussion of the demand response deployment probability in 2021 by the level of winter capacity.

Member Smith said the assumption is you're adding 3,400 MW. Kujala replied that it's 3,400 in the winter and 900 in the summer. But it doesn't meet the current adequacy standards.

Fazio said it meets the 5 percent standard, but the definitions have changed, instead of 2,500 in the winter and none in the summer, there is 3,400 in the winter and 900 in the summer. The ARMS were different in this case. But we're still producing adequate supplies.

Member Karier recalled in the RACC that there was some question if the winter imports should be high at 3,400 or constrained to 2,500. There wasn't an obvious answer. So they started with 2,500 and modeled 3,400. He doesn't recall whether summer should be zero or 900. In the summer, California would suck up all the power and there'd be no imports. Fazio replied that they didn't discuss it in the RACC, but they showed results from the energy GPS contract work. In that report, they saw there were several thousand megawatts

of available capacity in the summer. It would be high priced, but available. Karier observed that was getting into the “duck curve.”

Eckman said that the takeaway is there is a connection between the assumptions made between external supplies and the need to build resources locally. Whether it’s demand response or natural gas development, it’s cheaper than building something locally. That’s the risk statement. We’re asking the RACC and SACC to take this under consideration. The market access might be there, but it might not be at a price you like.

An updated scenario analysis shows little change in new gas generation development patterns across scenarios compared to Draft Plan, except for the “no demand response” scenario. The focus is on the “no demand response” scenario, since the other scenarios are all nearly the same. If you don’t have it, you need natural gas development. If not, there’s an 88 percent chance you’ll need natural gas development by 2021. If you have it, that probability drops to around 2 percent. This looks at it regionally. Seasonality is a big driver.

John Ollis, staff power system analyst, explained a chart addressing balancing and flexibility curtailment analysis fiscal year 2021. Most events are in the winter, Ollis said. We’re testing to see if the existing system can meet it. There are a lot of curtailments are in peak hours. Demand response and energy efficiency reduce the peak requirements, which allows the hydro to serve the balancing and flexibility. Sometimes there are all-day events, but with demand response and energy efficiency, they become more like ramping events.

Eckman said that when we’re talking about demand response, these events occur in poor water conditions and extreme weather events. They are systematically rare, so it makes it difficult to develop resources that are on the shelf most of the time.

Member Yost asked, “If we have a certain number of events and there’s curtailment, why don’t we send those customers a check and that will be demand response?”

Eckman said that the difference is programmatic. The customers are asked if they want to participate.

Eckman discussed the system cost and economic risk of the alternative resource strategies.
The existing policy case is about $82 billion. Without demand response, they incur a $4 billion cost to the system, so it has significant value. If markets are increased, it could reduce the present value system cost to $76 billion. The model is finding economic value to developing demand response. Developing more gas generation is more expensive.

There is little change in renewable generation development patterns across scenarios compared to the Draft Plan, even with revised capacity values. There’s a little more development, but it’s in the 10 percent range.

The observations are:

- The development of demand response slightly reduces the need for energy efficiency and significantly lowers the probability of building new natural gas generation.
    - Without demand response, average energy efficiency development increases from 1,300 to 1,400 aMW.
    - Without demand response, the probability of needing to build new gas generation by 2021 increases from around 2 percent to nearly 90 percent.
- A consideration of policies that are aimed at further reducing CO_2 emissions increases average energy efficiency development from 1,300 to 1,400 aMW.
- Without developing the Draft Plan's 400 MW of energy efficiency and approximately 600 MW of demand response, the region may not meet adequacy standards, and IT could have difficulty providing reserves for balancing and flexibility.
    - Alternatively, the region could build additional new gas-fired generation.
    - This alternative resource strategy increases system cost by $4 billion and system risk by $5 billion.

Observations Regarding Range vs. Single Value

- Within individual scenarios, the range of energy-efficiency development is much narrower than in the Sixth Plan.
    - Sixth Plan – 300 aMW spanned 80 percent of futures.
    - Seventh Plan – 40–120 aMW spanned 80 percent of futures.
- Across the scenarios, the 1,300 to 1,450 aMW span 80 percent of the futures.
    - The system is building for adequacy.
    - Not all scenarios are equally probable.

Two remaining Resource Strategy Action Items requiring a Council decision:

RES-1 – The Draft Plan's regional conservation goal – Bonneville, utility trade associations, and individual utilities recommended that the Final Plan specify the conservation goal as a range. Environmental and renewable energy advocates and many individuals strongly endorse retaining the Draft Plan's goal to develop 1,400 average megawatts of energy efficiency by 2021 as a minimum.

RES-4 – The Draft Plan's call for the development of demand response – Bonneville and utilities supported retaining the language in the Draft Plan's Action Item, which did not set a regional goal for demand response development. Environmental and renewable interest groups stated that the Final Plan should be specific about the level of demand response that should be developed, recommending 700 to 1,100 MW be targeted by 2021.

Member Yost said that in many chapters, we had the range and a single point. Why can't

we do that in all the chapters? We do it in some, but not in all of them, and I think the comments came from that.

Eckman said the Council can decide.

Member Anders asked for a reminder of the utility range. It's 1,300–1,450 aMW, which was consistent with the observations, other than the one without demand response. Eckman said with demand response, it goes down to 1,300, and without it, it goes to 1,400.

Member Karier asked the Council to consider a couple of alternatives:

First, the energy efficiency target: the acquisition of 1,350–1,500 aMW by 2022 is expected to lower total system costs and risks. For the purpose of planning and budgeting, BPA and the region's utilities should target the acquisition of a minimum of 1,400 aMW over the next six years, beginning in 2016. It's comparable to what was in the Sixth Plan, updated for these new results.

On demand response: In the mid-term assessment, the Council will determine if the region has made sufficient progress towards acquiring demand response or confirming additional import capability sufficient to provide the region with an additional peaking capacity of 600-1,400 aMW. He said he combined the demand response with the additional import capability.

Eckman said that the Action Plan speaks to that already.

Member Karier said that it's not an explicit target, but it indicates what the Council is looking for. We've seen that a minimum development of 500-600 MW of demand response or additional import capacity would be extremely valuable to the region.

Member Rockefeller suggests that they be taken up separately. I'm characterizing it as a blending of the range and a point, he said. Member Karier said he would retain the two-year milestone.

Member Smith said he would need more time to look at the results we have. He was comfortable with the 1,400 from before, the higher figure could be fine, given the new results we have. He said that looking at existing policy, which isn't much carbon regulation under the 1,300, and what Oregon and Washington are doing in their legislatures, the probability is there won't be any change in carbon policy over 20 years, so it militates in favor of being more realistic with that lower number.

Member Lorenzen said he was confused about why we're worried about a point estimate versus a range? Those who advocate for a range think there's a lower standard by having a range, because if they meet the lower number, they've hit the goal. I don't know if anyone would complain if we go beyond the range.

Member Yost said that in the Sixth Plan, there was a range and a target. After a couple of years, folks were nervous that we wouldn't achieve it. People wanted BPA to throw more money at acquiring conservation because we weren't projecting vigorous acquisition of energy efficiency. We had a lot of staff discussions about sending nasty grams and beating up BPA and increasing their budget for conservation acquisition. I don't care if we have target or a range, he said. But understand, sometimes this doesn't come in at so many MW a year of conservation. Sometimes you're low and sometimes you're high. If it's low, we'll investigate why and do what we need to correct it. No reason to be a lemming and jump off a cliff. We haven't been that way. People get excited, beat up on BPA and want utilities to pay more money. Utilities have to stay within a budget. It takes a year to get that in the rate case.

Member Lorenzen agreed. "What your comment is more toward how we respond to achievements rather than about how we set the goals. What do we do if we fall outside the range versus the target?"

Member Yost said if we underachieve, it's because we don't have the right incentive, program or people aren't responding to the utilities. Instead of throwing more money at it, take a look at what went wrong and solve that problem, not throw more money at it. That's what the case was in the Sixth Plan.

Member Karier said if we have a target, the alternative includes a target for budgeting and planning, but there's a level of uncertainty.

Eckman said we had this discussion in the draft. To Member Lorenzen's point, we'll monitor and respond accordingly.

Member Lorenzen said he's happy either way. The significant issue is how to deal with a possible shortfall.

Member Booth asked Member Karier if the range is the same as in the draft.

Member Karier said the range is 100 MW more. He was thinking of a 3-4 percent margin of error. He's not sure the upper range is that significant.

Member Booth remarked that it seems easier for the region to have a number. It seems as though 1,400 is simple. We don't have to explain why we have a range that way.

Member Karier said that he thought it worked the way it was, but we should take a look at a range because it was brought up from a lot of suggestions. He said he's comfortable with a target.

Member Smith said he's comfortable with 1,400 MW.

The Council elected to stick the current language.

Taking up Member Karier's demand response alternative demand response: In the mid-term assessment, the Council will determine if the region has made sufficient progress towards acquiring demand response or confirming additional import capability sufficient to provide the region with a peaking capacity of a minimum of 600 MW.

Member Karier said he did see this one changing. Demand response has a more valuable role. There's less of a range and less ambiguity. As we go into our midterm assessment, it should be one of the major things we're looking for: progress in acquiring demand response. If we add import capability, we can offset that amount. But if it's not there, there are significant risks to region if we don't get 600 MW. It doesn't assign it to individual entities; it looks at it regionally, but says that's what we're going to be looking at. I think this has value beyond "we'll work on it."

Member Anders asked where the 1,400 ceiling come from. Member Karier replied that the lower range seemed to be around 500-600 MW. In the upper range, it was more difficult. Basic policy more has more than 1,100 mw that in Draft Plan is likely to be valuable. He said he picked a number between 1,100 and 1,700.

Eckman said it might be better to set a minimum rather than a range. Getting the minimum is what's critical.

Member Bradbury asked about confirming additional import capability. Kujala said that we should back and reexamine our assumptions; perhaps we can rely more on our neighbors as they build more resources, rather than building our own.

Member Karier said to change the language to a minimum additional 600 MW and drop the range.

Member Rockefeller wondered at what cost would you have that capability. At some price, you could always import. Kujala said that with water crisis or California markets, we might not be able to rely on "some price." It's the art of adequacy. Where are we willing to rely on others and where are we going to rely on our own?

Member Karier said if we were not there, we'd want to evaluate WHY we're not there.

Staff will return with a redline version to review.

Future webinars

There will be a February 3 webinar. Council Members were asked to hold time on their calendars on February 3 and 4, to have more discussion.

Eckman said there are four additional scenarios on carbon policy options to present. They don't have implications for the resource strategy, but will influence the carbon policy narrative. They will be presented in February, or there will be an hour-long webinar in the interim. The scenarios will be run by then.

Shurts reminded Members that the Council couldn't take any public comment on the Plan or any issue affecting the Plan. The Council can elect to reopen the comment period.

6. Council Business

NORTHWEST POWER AND CONSERVATION COUNCIL MOTION TO APPROVE THE MINUTES OF THE NOVEMBER 17-18, 2015, COUNCIL MEETING

Member Booth moved that the Council approve for the signature of the Vice-Chair the minutes of the December 15, 2015 Council Meeting held in Portland, Oregon. Member Anders second.

The motion was unanimously approved.

NORTHWEST POWER AND CONSERVATION COUNCIL MOTION THAT THE COUNCIL AUTHORIZE STAFF TO EXECUTE CONTRACTS WITH DR. MICHAEL MC COY AND GWEN SHEARER TO PREPARE FOR THE REDEVELOPMENT OF THE GENESYS MODEL

Member Booth moved that the Council authorize the staff to execute contracts with Dr. Michael McCoy and Gwen Shearer to prepare for the redevelopment of the GENESYS model for a total amount not to exceed $80,000 for fiscal year 2016, as recommended by the staff. Member Yost second.

Fazio said that the Council is looking for a better microscope. He said we know the value of the GENESYS model and the others used for analysis. We're trying to take a model that was originally developed to handle energy deficits into one that also can handle capacity problems in a more explicit way. This is just a scoping effort. There are two parts to this contract: We want to make sure that in the hourly simulation of the hydrosystem that we have a more precise and representative simulation of what happens in the real world. Right now we're using an approximation. With more complexity with more variable resources (wind and solar) and our load changing shapes (distributed generation), it's more important to simulate the hourly dispatch of hydro in a more precise way. The second is to update the ways we treat data and bring it up to current standards. This also will allow more staff to use it as well.

The motion was unanimously approved.

NORTHWEST POWER AND CONSERVATION COUNCIL MOTION TO APPROVE THE COUNCIL'S ANNUAL REPORT TO CONGRESS FOR FISCAL YEAR 2015

Member Booth moved that the Council approve the Council's Annual Report to Congress for fiscal year 2015, as presented by staff. Member Bradbury second.

Mark Walker, staff public affairs division director, draft annual report was approved by the Council at the September meeting. It was put out for public comment, but there were none. The changes are internal changes discovered since the comment period closed, plus a couple of typos. In addition, a year was changed on a graph of cumulative energy efficiency since 1978. They need to change 2013 and put in 2014. Plus, there's a new letter from Bonneville Administrator Elliot Mainzer.

Member Rockefeller asked for an amended motion.

Member Booth moved that the Council approve the Council's Annual Report to Congress for fiscal year 2015 with changes made by the Members at today's meeting. Member Anders second.

The motion was unanimously approved.

Election of officers

Member Yost placed Member Henry Lorenzen in nomination, commenting that he's a quick study in energy efforts, he's fair and gives everyone an opportunity to speak their piece. Member Smith second.

The motion was unanimously approved, with applause.

Member Rockefeller said, "It has been a real pleasure to serve as your Chair and be your colleague. It's been a learning experience to be a part of the Council these last four-and-a-half years, and I also have benefitted from this wonderful staff. We have the finest staff in the Power Division that we could possibly have, and a wonderful team in the Fish and Wildlife Division, and everywhere else at the Council. It's made my life easy."

He expressed his appreciation for Peter Cogswell as the Council's liaison with Bonneville. "We have a built-in, necessary tension," he said. "We have a dual mandate and have to provide parity for these mandates. It's not an easy thing to do. Bonneville is on the receiving end of that sometimes. We know we need to have a team effort with them and most of the time we succeed. I'm looking forward to the months ahead. Henry, congratulations."

Member Lorenzen thanked Member Rockefeller for his great service, and that he's disappointed that he won't have another year under his leadership.

He said the bylaws call for Members to elect a Vice Chair.

Member Anders nominated Member Bill Booth for vice chair. On the surface it appears all the vice chair does is move motions, but there's a lot of behind the scenes. Member Booth has done a wonderful job handling those matters, including serving as the Council's liaison to Canada. Member Bradbury second.

Member Lorenzen moved to close nominations. Member Bradbury second.

The motion was unanimously approved, with applause.

Public comment

Scott Levy, Idaho, has been involved in salmon recovery efforts since he made a documentary film on the topic. It played on public television in 1999 and it did well at film festivals. He said he's hopeful that everyone will read his comments about the Seventh Power Plan.

He wants to bring Council attention to a fish passage center memo from October 15, 2015: "Request data summaries and actions regarding sockeye adult fish passage and water temperature issues in the Columbia and Snake Rivers." The reason the memo is interesting is because only 46 sockeye swam to Idaho. There were 4,000 in the forecast. It was about 1 percent of the expected return. Temperature was the issue. Also, 2 percent of the sturgeon in the CR also died. He said he heard that when they sliced the sturgeon open, they were filled with sockeye. No new births of sturgeon were recorded.

He read from the memo, which goes into how temperature of water is a concern, and he said that the report says very little has been done. He asked the Council to read the memo and take his comments into consideration.

The meeting adjourned at Noon.

Approved February ___, 2016.

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Vice-Chair

Member Karier said that the Council's methodology was to use an RPM model which individual utilities don't. So are utilities not using the same methodology? Grist replied that they could use the methodology for cost effectiveness of measures, independent of the RPM. It is used to derive the overall level of conservation, including the capacity contribution. The utility can take the methodology for cost effectiveness and apply it with their various inputs.