**DRAFT**

**Northwest Power and Conservation Council**

**Resource Adequacy Advisory Committee**

**Technical Committee Meeting**

**January 28, 2016**

**Meeting Notes**

John Fazio, NPCC, opened the meeting at 10:00, and noted that Robert Diffely, BPA, is serving as his co-chair. He stated that the meeting is part of preparing for the 2021 Adequacy Assessment and called for introductions around the table and on the phone.

Fazio noted that because the meeting is being held after the closing of the Seventh Power Plan comment period, Council staff cannot take comments related to the Plan [Slide 2]. He stated that his goal for this meeting was to gather enough information to run preliminary studies and present results in about a month.

**AGENDA**

Fazio stated that items have been added to the Agenda [Slide 3]. The added items include a discussion about standby resources, market friction and fuel supply limitations related to the adequacy assessment for 2021.

Steve Johnson (WUTC) began by discussing more broadly on what the Council does and suggested calling on the region and the utilities to step up and provided needed information to the Council to better facilitate the regional resource adequacy assessment. He suggested looking to the California ISO (CAISO) as a possible source of helpful information related to assessing adequacy. He was concerned that using the current methodology could result in the region being assessed as adequate when in fact, it may not be – potentially adding unnecessarily high costs for regional consumers. Thus, he endorses the review of the current Northwest adequacy standard.

Fazio suggested holding the question until the last agenda item: Review of the Council’s Regional Adequacy Standard. He then stated that both he and Ben Kujala, NPCC, are members of the International IEEE Loss of Load Expectation work group and stated that every region is struggling with this question.

Fred Huette (NW Energy Coalition) agreed with both parties but agreed that it might be useful to look at what CAISO does as it is a bit different. Huette then mentioned a later agenda item: Update on Idaho Solar and noted that the BPA has a new solar task force that might be something to look at later.

Johnson stated that he was not necessarily speaking to the modeling process, which is complex by nature, but to the difficulty in getting the basic operational information from all of the utilities. He stated that CAISO has a strong requirement to report while utilities here are not bound to report. He asked if we should obligate providing needed information to the Council for its adequacy assessment.

**GENESYS Model Enhancements**

Fazio described recent enhancements and corrections made to the GENESYS model. Tomas Morrissey (PNUCC) asked if the improvements fixed the weird 2-AM curtailments. Fazio answered yes, saying that while the model isn’t perfect, resulting simulated curtailments look much more reasonable.

Villamore Gamponia (PSE) asked if this pertains to when a curtailment lasts more than a week. Fazio answered no, saying that a curtailment that lasts more than a day or a week tends to be an energy problem and not a capacity problem. He offered to talk about the need to examine long curtailments later or offline.

**Action Item**: Add a discussion of long curtailments to a future RAAC technical committee meeting agenda. Prepare statistics and other related data for long curtailments to aid the discussion.

Fazio noted that the Council has contracted with Gwen Shearer to add code to GENESYS to model solar simulation in a similar manner in which wind is simulated. Johnson asked how important temperature correlation is for solar. Fazio admitted he didn’t know but said it was important to explore; saying that the correlation the Council is looking for is the relationship between temperature (load) at the delivery point (load center) and generation at the solar (or wind) site.

Fazio moved to the **Hydro Pricing for Hourly Hydro Shaping** item. Morrissey brought up his concern that the current version of GENESYS does not model a California demand for surplus NW power. His concern is whether the lack of a California demand market would affect the NW adequacy assessment. He said that without such a market, some surplus water would be held back, thus improving adequacy in future time periods. He asked if an out-of-region demand market will be discussed later. Fazio answered yes, saying the addition of that market is needed and that it could very well affect the adequacy assessment, although he did not think in a significant way. He noted that this issue will be discussed later in the agenda.

Gamponia asked if the hydro pricing profile is the same across all games and all periods and whether that information is available to RAAC members. Fazio said the information is available but specific output files have to be turned on. Fazio stated that he would be happy to prepare a sample output file that illustrates how the hydro pricing works for the hourly dispatch.

**Action Item**: Prepare sample hydro pricing output files to illustrate how hydro pricing affects the overall dispatch of all resources for a future RAAC meeting.

Cam LeHouillier (Tacoma Power) asked how the extension of tax credits for wind and solar resources would affect the Council’s adequacy analyses. Fazio answered that tax credits for new resources are not used in the resource adequacy assessment, which is calculated using existing or expected-to-be-operational resources only. He did note, however, that the adequacy assessment does assume that the energy efficiency targets, as outlined in the Sixth Power Plan, will be achieved. Phillip Popoff (PSE) asked for the RAAC to review the changes in the conservation assumptions because they have “changed a lot.” Fazio agreed.

The discussion then moved to the issue of fuel supply for the **Grays Harbor** plant[Slide **5**]. Fazio noted that GENESYS assumes an infinite gas supply for all gas-fired resources. Phillip stated that Grays Harbor does not have a firm gas contract and therefore, may not have fuel during high demand hours.

Popoff discussed PSE’s IRP saying that he has tried to make it consistent with the GENESYS methodology, whenever possible. He said that PSE has looked into Grays Harbor’s fuel supply and determined that below a temperature of 37 degrees Fahrenheit their gas would not be available. He stated that GENESYS needs to reflect a situation like that, for gas-fired plants that do not have a firm fuel supply.

**Action Item**: Phillip will provide the RAAC with information about the availability of gas for the Grays Harbor plant as a function of temperature. Phillip said that the information can also be found in Chapter 6 of PSE’s IRP.

Fazio then asked if the availability of non-firm gas is only a question of price, that is, if money were no object could PSE obtain gas for the Grays Harbor plant? Popoff said that would be a good question for the gas association. Fazio stated that adequacy studies don’t take price into account. He noted there are other models, like the RPM, AURORAxmp and utility models used to develop IRPs that take economics into account.

Fazio said that GENESYS already includes daily average regional temperatures and that logic could be added to reduce any project’s generating capability as a function of temperature.

Tom Haymaker, Clark PUD, shared Popoff’s concern and suggested looking at the NW Gas Association’s outlook to get a sense of pipeline availability. Fazio agreed.

Diffely asked Popoff if this is a west side or east side issue. Popoff stated that it’s an I-5 corridor issue and that there is no capacity problem on the east side.

Johnson asked if there would be spare gas supply from Jackson Prairie at 37 degrees F that could displace I-5 gas. Popoff said that Avista might sell you gas but PSE would not and noted that 37 degrees F is a “yellow light,” meaning that at that temperature and below, the gas supply is uncertain. Popoff said this could be a good leading topic with Ed Finklea and Northwest Industrial Gas Users, as there are industrial gas customers who will sell gas under the right conditions.

Johnson went back to 37 degree F issue, reiterating his understanding that at that temperature PSE owned and contracted gas capacity on the pipeline is fully allocated and PSE would not sell any. Johnson then pointed out that GENESYS models all of the output in the region collectively, that is, as a single utility. He concluded by saying the model should share any spare gas in the region (e.g. at Jackson Prairie) with whatever projects need gas during high loads.

Morrissey said that it shouldn’t be too difficult to derate a plant’s capacity as a function of temperature. He referenced Avista’s 2013 IRP as an example.

Huette admitted he doesn’t know much about Grays Harbor but mentioned that it doesn’t seem to be run much (by looking at historical data). Fazio said it would be interesting if we knew what the conditions (temperatures) were during the times that it was run. Was it run for economy or was it run for adequacy? Huette agreed and added that it looks like Grays Harbor doesn’t run much in the winter.

Fazio brought up the topic of fish constraints on the hydroelectric system, saying that GENESYS doesn’t curtail bypass spill for fish. In other words, GENESYS has an infinite cost for curtailing bypass spill, even though the BiOp has a clause to allow for its curtailment during energy emergencies. Fazio said, however, that in 2001 bypass spill was curtailed, implying that the cost to curtail spill is not infinite. He said that in a way this parallels the issue regarding non-firm gas. What if gas were available during extreme load events but was very expensive? Would a utility curtail load before it paid for very expensive gas? Fazio didn’t think so but he said that this brings up an important question about what the adequacy assessment is used for. Fazio said that a situation could arise when GENESYS concludes that a power supply is adequate but very expensive “emergency” resources had to be used. The adequacy assessment is not designed to assess whether a power supply is economical or efficient. But if such a case were to arise, Fazio wondered if the conclusions would be misleading. In other words, for that case GENESYS concludes that the power supply is adequate, which implies that no actions need to be taken. However, an RPM (or IRP) analysis would conclude that resource actions must be taken to make the supply economical.

**Differences between the Council’s long-term and short-term load forecasting models [Slide 4] were then presented by Massoud Jourabchi (Council).**

Jourabchi briefly explained the differences between the Long-Term Load Forecasting Model (LTM) and the Short-Term Model (STM). The LTM is an end-use model, which includes the effects of standards and codes. The STM is an econometric model, which uses historical loads to project future trends and does not include the effects of standards and codes.

Litchfield was concerned that the two forecasting models could produce different results. Jourabchi said that the short-term model does a good job of projecting hourly loads as a function of temperature and, therefore, is best for forecasting near-term (1 to 5 years out) peak loads. The long-term model does a better job of projecting energy loads over the planning horizon (20 years). He said that he has compared the two forecasts and determined that the energy loads are very close but that the peak load projections can be further apart.

Litchfield reiterated that this “decades-old problem” of presenting a forecast that has two values that are thousands of megawatts apart still exists. He suspects that this is a communication problem and suggested that the Council develop a way to consistently present peak loads five years out. Litchfield understands that there are a lot of variables involved and that explanations exist to describe the differences between the load forecasting models. However, he said the Council could lose some of its credibility when two load forecasts for the same time period differ substantially.

Kujala agreed with Litchfield and said this topic will be taken up as part of the Action Plan and will be examined by this group and others. He then pointed to the fact that the adequacy assessment uses a fairly arbitrary range between low and high load forecasts (plus and minus 2.5 percent), which is inconsistent with the RPM load range (generally a wider range). He called for the RAAC to think about this topic as it will be examined at a later date.

Fazio summed up saying that the RAAC and the Council need to come up with a better way to consolidate and explain differences between the two load forecasting models, keeping in mind that GENESYS needs hourly loads and that including the effects of standards and codes is very important.

Kujala reminded the group that no matter what, there will always be some inconsistency – but we should work towards being as consistent and clear as possible.

Popoff agreed with Litchfield, adding that the adequacy assessment is very sensitive to the load forecast. Thus, having two different load forecasts will only add to the confusion. He suggested a work plan item for the technical committee to really walk through and understand how the load forecasting models work and how conservation is incorporated into those forecasts. He said he would have no problem accepting the value of conservation if he understood the details.

Kujala agreed to commit to that. Fazio gave an overview of what the RAAC technical committee did last year. Kujala stated it would be better to have a complete conversation after the Seventh Plan comment period ends. Fazio agreed.

**2021 Resource Adequacy Assessment Standby Resource [Slide 6]**

**Presented by Rob Diffely, BPA**

Fazio noted that standby resource capacity went up in summer and went down in winter but that the energy contribution remained the same. He stated that the program to incorporate standby resources into the adequacy assessment (currently a post-processing program) needs to be amended to account for the seasonal nature of emergency resources. He suggested that the post-processor keep tabs on the hours of use rather than the total energy available as the limit for standby resource dispatch.

Fazio then explained how DR is taken into account. He said that already-implemented (in the historical load record) DR should be accounted for in the short-term load forecast and new DR (not yet implemented in real life) should be a part of the standby resources.

Morrissey asked if the problem with modeling DR can be eliminated by switching to a more long term forecast. Kujala answered that forecasting loads by end-use would give you more credibility. Fazio agreed but stated that GENESYS needs hourly loads so we would still have to extract the hourly load shapes as a function of temperature.

John Ollis, NPCC, reminded the committee that GENESYS tests many water years against a particular load condition and the DR hourly shape may not be the same for every water condition. He concluded that end use loads might be more productive.

Fazio stated that the RAAC needs to examine in more detail how DR is incorporated in the short term model. Kujala stated that there are many ways to solve this problem, saying that in the past DR was folded into the load and that we may need to reconsider this approach, depending on what data are available.

Zac Yanez (Snohomish) asked about discounting DR on the curtailment or customer/load side to account for the sub-optimal discount. Popoff answered that the concern about DR is that it’s easy for a utility to do it within their BA but there are serious market barriers across BAs especially if one of them is the BPA.

Ollis stated that utilities acquiring a firm DR resource would have applied any discounting in their resource plans. Kujala stated that if you tied it to specific loads you might not have to discount it. Yanez asked if there was a way to tie that into the logic. Kujala said it’s under consideration as DR grows.

Popoff cautioned about a “language to math” issue with DR, stating that when we say 120 MW we mean the effective capacity, which might mean that we need 300 MW of contracts. Kujala agreed and stated that’s an input issue. There were head nods of agreement around the room.

Morrissey asked how standby resources are deployed. In other words, is there a maximum number of hours for each resource or a maximum energy and capacity limit? Fazio stated that the model currently uses monthly capacity limits for standby resources and limits their total annual dispatch to a maximum amount of annual energy. Pat Byrne (BPA) stated that if you use up all the energy for a standby resource during winter, it will not be available for summer use. Fazio noted that this is something we want to change as some DR is only available in the summer (this was also mentioned in the notes above).

Morrissey asked if you could run Banks Lake continuously until it’s out of water. Fazio answered no, saying 40,800 hours is the limit for all stand-by resource energy. Diffely pointed out that the Council models capacity and energy differently. Kujala explained the process.

Morrissey asked if standby resources could be limited in other ways, such as to be available only during certain time periods of the day and for a limited number of hours. Fazio and Kujala agreed that stand-by generation characteristics have to be discussed further.

Johnson asked about standby resources listed on the slide and what criterion is used for determining prospective DR resources. Fazio answered that the overall criterion used in the adequacy assessment is that a resource must be sited and licensed or expected to be operational in the year being examined. Kujala added that that’s a way of saying we don’t really have one. Johnson thanked them for their candor and suggested moving on.

Fazio moved on to discussing intertie uncertainty. Huette stated that the DC intertie has been upgraded, resulting in a dramatic improvement in performance. Fazio agreed that the upgrade should be taken into consideration. Kujala mentioned that there are several approaches for looking at that but we need to break it into two separate uncertainties: transmission and out-of-region market supply.

Popoff brought up meetings with PNUCC and CALISO that discussed fuel supply limitations. He noted that they are summer peaking but are looking at how much they have in the winter.

Morrissey asked how IPP wind is modeled. Fazio said they basically ignore it and model only the firm NW wind, but stated he’s open to discussing better alternatives for how to deal with the approximately 3,000 MW of IPP wind.

Ollis said we don’t ignore the wind from a balancing perspective, that is, balancing reserves must be maintained for all wind, not just NW wind. Yanez asked if you can assume you can re-dispatch some balancing reserves during an adequacy event. Fazio answered no, as the model is not a sub-hourly model. Yanez asked if we should look at how re-deploying half of the reserves during an adequacy event effects LOLP. Fazio did not think that would work and explained why.

Yanez insisted that a BA could pay someone to hold back reserves during an adequacy event. Ollis stated he would hesitate to reuse reserves unless you also assign reserves to the thermal units. Kujala suggested that there could be more systematic approaches that would allow more work on that but in a situation where you are curtailing load you would look at the wind fleet. Yanez agreed that it is state dependent. Kujala said it’s a good question but it’s more operational than planning.

Huette pointed to the changes in the winter hydro modeling in BPA’s White Book and asked if they would be folded in. Fazio answered yes as soon as he gets the BPA data.

Huette asked about the rule curves. Fazio explained them.

**Market Friction**

Fazio asked if modeling uncertainties in the import supply and the intertie availability are sufficient to cover “market friction” or whether we need to deal with it separately. Yanez answered that it depends on how much of the intertie is left open for operations. Kujala brought the conversation back to planning versus operations and asked if we should be planning for market friction and if so, what a reasonable planning assumption might be.

Yanez stated that the closer you get to an event the more likely there will be market friction. Fazio stated that he doesn’t lock in the 2500 MW but just marks it as available. He stated that he could use temperature extremes as a way to knock down the availability but stated that the overall question is, should we even do that or does the 2500 MW incorporate enough uncertainty. Kujala restated asking what the drivers should be: extreme temperatures, high forecast error or anything else.

Popoff stated market friction, standby resources and SW imports get tied together, and noted that he was never clear about the 3400 MW and 2500 MW of spot plus firm contracts. He noted that he fills the gap up in his IRP and assumes the full 3400 MW of imports. He stated that there are variables (bad hydro year, extreme weather and thermal outages) that cause uncertainty and might make utilities refuse to sell power. He admits he doesn’t know how or if they should model it but during the “white knuckle time” of energy limitations, market friction is real.

Fazio stated that he can’t model market friction within the nodes. Popoff suggested looking at resources and notice that some--like standby--might go unutilized and illustrated the point by saying that PGE would let PSE lights go out before they turned on their standby generators. PGE said they would use their standby resources to help PSE under the proper conditions.

Popoff suggested separating market friction from the California import question as it goes beyond that. He would like to have a conversation about what those imports would be again saying that he counts 3400 MW.

LeHouillier stated that resource adequacy is about keeping the light on regardless of price and adding market friction muddies the water. He stated that if price is not an issue in other parts of the model it shouldn’t be here either.

Morrissey moved to the import question saying he’s curious about how often a lack of spot market causes a curtailment versus a full intertie during high stress times. He said that the 2500 mw might not make a difference as you get to the 3400 mw because of the day-ahead market. Fazio stated that he could supply some information.

Huette stated that he was never clear or happy with market friction. He noted that inaccurate weather forecasts are not market friction. He moved to his concern with imports, saying that there is new thinking about interregional transfers noting that you could notify California generators that they might be needed. He called it an evolving situation that goes beyond market friction.

Johnson stated that we are trying to model reality. He suggested knowing what one BA does when another BA is short and that this analysis should include California. He also noted that we should model the capability to harness resources in an emergency and keep it separate from the day-ahead market.

Kujala said we use the word curtailment too loosely in this situation. He stated that “peak stepping in” is similar to violating the spill constraint. He noted that it might happen but it wouldn’t go into the planning assumptions.

**LUNCH**

**The Value of GENESYS [Slide 7]**

Popoff asked if Fazio looked at a winter, ELCC-type metric for solar. Fazio said yes and it will be in the final Power Plan.

**GENESYS Enhancements [Slide 11]**

**Detailed representation of out-of-region demand and supply**

Morrissey suggested looking at historical temperature and see what is exported on the intertie and develop a parameter from that. Fazio stated there are lots of options including modeling individual CA resources. Morrissey felt that would be a good addition.

**Forecast weekly flow volumes and use load and flow forecasts for hourly dispatch.**

Johnson stated that looking at weekly forecast of flow volume is trying to model how operators think. Fazio agreed saying it’s the flow forecast feeds into the setting of hydro pricing, which determines how aggressively hydro is used. Johnson stated that there is more certainty in the day ahead versus the week ahead.

Huette said that getting this microscopic could be problematic as things change including the individual operators. Fazio agreed saying that operational actions can be different for different schedulers and is clearly subjective. Huette was comforted by the Council’s close relationship with Bonneville which gives it the opportunity to “true up” the model.

Mike Landau, Snohomish PUD, asked if the BPA had plans to retire or redevelop HYDSIM. Fazio said that BPA is working on developing a new model for scheduling but HYDSIM is not going way. Both Diffely and Byrne confirmed this.

LeHouillier suggested considering adding an error term to the dispatch of the model. Kujala stated that you get into a multi-state commitment where you find out what is committed and what will change because of that commitment.

Sarang Amirtabar, Seattle City Light, asked if there were any problems with adding the Southwest nodes to the model. Fazio answered that it wasn’t a problem splitting the east node into east and Idaho nodes but a problem arose with the hydro peaking approximation. He explained the issues and suggested a plant-specific hourly dispatch as a possible solution.

Haymaker asked if Fazio foresees the 5% LOLP changing with the possible GENESYS changes. Fazio answered yes but not because of this process but because it’s too simple and at least quarterly LOLP targets are needed for the RPM. Haymaker asked if we would be comfortable with a LOLP higher than 5% because you’re more certain about it. Fazio acknowledged the point and said they will be looking at other metrics and thresholds throughout the process. Kujala reminded the room that every probability is conditional and based on assumptions. Haymaker agreed.

**Popoff stated through in his modeling he’s found that small changes in LOLP can mean doubling the amount of unserved energy. He felt this would be a good topic for a RAAC Steering Committee**.

**GENESYS Enhancements [Slide 12]**

**Rewrite the FORTRAN Code**

Johnson suggested considering succession planning when looking at code (e.g. when current coders retire can younger coders be found who know the modeling language). He wondered how common the language is among a younger cohort. Kujala assured him that it is not an uncommon code, particularly among people who do mathematical modeling. Huette stated that FORTRAN is not a legacy language but that the talent pool is shrinking over time. He noted there will be people using FORTRAN for a long time and you could always add a non-FORTRAN interface program to manage data and studies.

**GENESYS Enhancements [Slide 13]**

**Are there other uses for GENESYS Output**

**Emission Studies**

Morrissey recommended a demand curve if GENESYS is to be used for emission studies. Fazio agreed.

Gamponia said PSE would like to see the forced outage profile for each plant. Fazio said you can get that now but it’s complicated and the goal is to make it easier.

Huette stated that it’s one thing to clean up a model but this looks like more than that. He supports this use of resources and will come up with other features he thinks the model should have.

Litchfield recalled that GENESYS had long-term expansion logic in it at one time and advocated thinking about adding it back in as it can give a higher-level, more detailed analytical definition of what’s going on hour-by-hour. He felt that GENESYS and the RPM could cross check each other. Fazio said that would require adding long term load uncertainty. Litchfield agreed.

Litchfield then said he supports having some uncertainty analysis for energy efficiency. Fazio agreed and added it to the slide.

Litchfield then expressed concern about running fish survival studies. Fazio explained that his intention is not to add fish survival logic to GENESYS but rather to understand what outputs are needed by those models.

Landau suggested looking at ramp rates. Fazio agreed and said that unit commitment logic has already been added but has not yet been tested.

Morrissey asked how, when looking at ramp rates, GENESYS currently deals with large shaft resources, such as coal. Fazio said the model currently has a “one-day commitment” logic – if a coal plant is needed, it must run for at least a whole day. Huette said this will become more an issue as a wider range of flexible resources comes on the system.

**GENESYS Redevelopment Scope**

Amirtabar asked if bad or surplus events can be pre-sampled. Fazio said yes and it can be done now.

Huette asked for an explanation of how the three “big tent” meetings would go. Kujala said we will bring a strawman proposal to the first one, which gives the committee something to think about.

Morrissey asked if a goal of redevelopment is to increase the amount of end users or is it more for current users. Kujala answered that one of his goals is a smooth succession after Fazio’s eventual retirement, which means that the program has to be well documented and very usable so a new person can run a special study easily and quickly.

Morrissey called for a prioritization of the development items.

**Review of the Council’s Regional Adequacy Standard**

**Fazio, Kujala and Ollis presented**

Huette said that there was a vigorous process in developing the LOLP as the Council’s adequacy metric in 2011 and praised many agencies for their sharper thinking on this issue. He expressed doubt that there will be a best possible single metric that folds in everything else. He feels LOLP will continue to be valuable but is open to looking at other indexes. Fazio agreed but stated that we need a specific threshold for whatever metric we use to separate adequate supplies from inadequate ones. Huette felt that a “caution zone” might be more appropriate.

Ollis said that LOLP offers a simple message which is hard to do in the technical world and that simple message has value. He admitted that it will be hard to wrap frequency, duration and magnitude up in a single number.

Fazio said there may be value in looking at using the dispatch rate for a rarely-used resource as a metric. He explained if the resource is slotted for use once every 10 years but is used more than that then you are not at the right level of adequacy. Huette praised the Council for looking at how sensitivities move the LOLP around.

Popoff said if we move from LOLP then we need to know the objective criteria, i.e. the “red light” vs the “yellow light.” He stated that in his IRP they use the value of lost load.

Litchfield stated that there probably will not be one, magic-dial metric. He stated that there are two problem statements: 1.) we need something that communicates with decision makers that is simple and transparent. 2.) For people in this room we need the story that you take from the model. Is this a February problem? An August issue? He said we don’t parse the problem enough.

Kujala agreed but said as planners we need to know that the plan we’re making is giving us an adequate system. He said the harder problem is looking at a future system and it would be fine to throw three or four metrics at that. He concluded by saying that is not the message you would be bringing to decision makers.

LeHouillier agreed with Popoff saying a report card for the Council staff to use would be helpful. He noted that the Council staff provides analytical leadership to the region and individual planners gain credibility by tying closely to the Council and if you stray too far from the 5% LOLP it raises questions. He said he’s okay with adding a report card of metrics but asked the Council not to get rid of the LOLP metric.

Fazio acknowledged that it would be hard to toss a standard that we’ve had for a while. Kujala stated that it would probably look like LOLP plus refinements which might not change the message that goes to the broader audience.

Fazio explained the difficulty of using an annual LOLP for quarterly work. **He asked for guidance on what a 5% ALOLP really means on a quarterly basis**.

Kujala said the question may not even be quarterly but what is the right way to judge if a resource plan is adequate.

Morrissey said GENESYS breaks out curtailments by month now. Fazio agreed and showed the graph from the State of the System report. Ollis reminded the group that because the system is changing the metric that tests an adequate system needs to change too.

Yanez asked if cost could be a metric of adequacy, i.e. if it costs more to keep the lights on than the curtailment. Litchfield stated that it’s always cheaper to curtail but people lose their jobs.

Kujala said he was open to considering value of lost load as an approach but said that any one, stand-alone metric has a problem.

Someone on the phone asked what was meant by multiple constraints versus a single LOLP. Kujala gave an example of using the single largest loss of load along with a 5 percent LOLP. He said that this would keep the 5 percent LOLP standard but also limit the worst case loss to a predetermined level that was acceptable to all.

Fazio stated that a Doodle Poll will go out for a meeting in March. He closed the meeting at 3pm.

**Attendees On-Site**

John Fazio NPCC

Ben Kujala NPCC

John Ollis NPCC

Sarang Amirtabar Seattle City Lights

Tomas Morrissey PNUCC

Fred Huette NW Energy Coalition

Mike Landau Snohomish PUD

Cam LeHouillier Tacoma Power

Will Price EWEB

Jim Litchfield Independent

Zac Yanez Snohomish PUD

Ryan Egerdahl BPA

Rob Diffely BPA

Steve Johnson WA UTC

Pat Byrne BPA

**Attendees via Conference Call**

Bill Henry EQL Energy

Cameron Yourkowski Renewable NW

Janet Phelps PSE

Phillip Popoff PSE

Shawn Davis

Tom Haymaker Clark PUD

Villamore Gamponia PSE

Yochanan Zakai WA UTC

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