

Generating Resources Advisory Committee Meeting

October 2, 2014

Meeting Time: 10:00 A.M. to 2:45 P.M
Meeting Location: Northwest Power and Conservation Council
Facilitators: Steven Simmons & Gillian Charles, NW Power & Conservation Council
Note Taker: Amy Milshtein
Attendees: On-site

Steve Simmons	Northwest Power and Conservation Council
Gillian Charles	Northwest Power and Conservation Council
Jeff King	J.C. King and Associates
Tom Eckman	Northwest Power and Conservation Council
David Nightingale	WA Utilities & Transportation Commission
Kurt Conger	Northern Wasco Co PUD
Paul Dockery	Clatskanie PUD
Thad Roth	Energy Trust of OR
Jeff Kugel	PNGC Power
Greg Mendonca	PNGC Power
Tom Haymaker	Clark PUD
Robert Brown	Portland General Electric
Fred Huetten	NW Energy Coalition
Cameron Yourkowski	Renewable NW
Ehud Abadi	BPA
Robert Petty	BPA
Catherine Gorrell	Oregonians for Renewable Energy Progress
Kathleen Newman	Oregonians for Renewable Energy Progress
Jim Gaston	Energy Northwest
Dan Davis	Army Corps of Engineers

Attendees: Via GoToMeeting
Brian Dekiep, Northwest Power and Conservation Council, State Staff Montana
Dave LeVee, Pwrcast
Ryan Hoppe, Tacoma Power
Keith Knitter, Grant County PUD
Russ Schneider, Flathead Electric Cooperative
Bryan Neff, California Energy Commission
James Gall, Avista
Zac Yanez, Snohomish PUD
Elizabeth Osborne, Northwest Power and Conservation Council, WA State Staff
Rick Sterling, Idaho PUC
Robert Diffely, BPA

Anna Kim
Sibyl Geiselman, EWEB
Tomas Morrissey, PNUCC
Tom Kaiserski, Montana PSC
Leann Bleakney, Northwest Power and Conservation Council, OR State Staff

Welcome and Introductions

Presenters: Steven Simmons and Gillian Charles, Northwest Power and Conservation Council

Steve Simmons began the Generating Resource Advisory Committee and introduces the GRAC Team.

The GRAC meeting attendees introduce themselves.

Simmons calls for edits to posted GRAC meeting minutes from May 2014 and goes over the agenda for the day's meeting.

Simmons explains the role of the GRAC.

Gillian Charles, NW Power and Conservation Council, asks for input on two issue papers: **High Level Indicators for the Power Plan** and **Methodology for Determining Quantifiable Environmental Costs and Benefits**. She notes that comments are due October 31 and that both papers are posted on the Council's website.

Kathleen Newman announces an OREP and PGE hosted tour of the Salem Smart Power Project.

Proposed Work Plan for Seventh Plan Development

Presenter: Tom Eckman, Northwest Power and Conservation Council

Tom Eckman, NW Power and Conservation Council, explains the Council's analytical process flow. He points to major presentations and major decisions leading to the development of the draft Seventh Power Plan. Eckman explains the Major Seventh Plan development milestones. He calls for the GRAC's special attention to the decision rules for generating resource development, capacity and flexibility, and the demand response (DR) piece. Rob Petty, BPA, asks "where would the DR supply curves be developed?"

Eckman answers, "The generation side will be here in the GRAC and the conservation side in the CRAC."

Preliminary Assumptions for On-Shore Wind Technologies

Presenter: Gillian Charles, Northwest Power and Conservation Council

Charles reviews the wind power discussion from last meeting and outlines today's discussion. Charles then reviews technology trends including increased turbine nameplate capacity, hub height, and rotor

diameter. She also notes that Class 2 and 3 turbines are being developed in both lower and higher wind speed sites.

Charles discusses two Wind Power Classification maps from NREL, one for 80m hub heights and one for 100m heights. She notes the increased ability to capture resources with the 100m hub height. Kurt Conger, Northern Wasco PUD, notes that the second map includes offshore wind and wonders why the first map excluded it. Charles answers that she thinks it is just the scope of the maps because there would still be offshore wind resources at the lower hub height. She continues that this meeting only focuses on onshore wind as the GRAC discussed offshore wind at the last meeting. She notes that offshore wind is “one technology that’s farther out for this plan but it is one to watch.” She discusses NREL’s final map and points to opportunities for future development.

Jeff Kugal, PNGC Power, asks for average hub height in service right now. Charles answers that it is probably 80 meters but that she doesn’t know for sure. Cameron Yourkowski, Renewable NW, agrees with 80m hub height.

Cost Trends

Gillian Charles discusses cost trends for wind technology, noting that installed project costs continue to decrease from 2009/2010. Charles also notes that the Power Purchase Agreement (PPA) prices have dropped significantly over the last five years from \$75 per megawatt hour in 2008 to \$25 in 2013, however; she acknowledges that much of this movement happened in the interior United States (source – DOE’s 2013 Wind Technologies Market Report). She feels that in this report a cost of \$25 per megawatt hour may be an outlier and specific to the interior where costs have traditionally been lower. She also points out the West has traditionally higher PPA prices than the interior and other parts of the US.

Capacity Factors

Gillian Charles discusses capacity factors based on data compiled by Berkeley Lab. The report shows a general increase in recent years but Charles notes that the trend is not as significant or consistent as would be expected. She points to aging infrastructure which may be dropping down the average. Charles also points out that there is curtailment included in the chart and notes that the quality of wind resource areas in projects currently in production may influence the capacity factors as well. “We think new projects will have a higher capacity factor,” she says. Kurt Conger, Northern Wasco PUD, asks if these are national numbers, Charles answers “yes.” Cameron Yourkowski, Renewable NW, asks how the information factors into current assumptions. Charles states that they are for overall trends and illustrative purposes only.

Charles then poses the question of manufacture modifications on capacity factors in the NW. Do taller turbines, longer blades and greater sweep areas improve, decline or have no effect on capacity? She notes that she has examples of capacity factors from the Sixth Power Plan along with the hourly wind profiles from Aurora 2008-2010, and EIA Annual Generation Data 2008-2012.

Ehud Abadi from BPA asks, “Is there an average for these numbers? What is the standard deviation from year to year? Do we get the same amount of wind from year to year?” Charles doesn’t have that information on hand but says that it can go from 5-10% depending on the wind year.

Fred Huetten, NW Energy Coalition, asks for annual NW Wind factors. He calls into question a fact from a past meeting stating that the wind variation is the same as the hydro variation. Charles will provide specific wind project data behind the EIA numbers at the next meeting.

Dave Nightingale, WA Utilities & Transportation, questions the EIA Annual Generation table. He wonders if the capacity factors are skewed toward old technology and suggests looking at the last year and half for data instead. Charles suggests starting with the Sixth Power Plan numbers and making adjustments from there might be a better solution, but asks for GRAC input on those numbers. Robert Brown, PGE, answers that the estimated capacity factor for Tucannon is 36.8%. Charles asks, “So we should raise our numbers?” Brown says “yes. Oregon and Washington have the same geography in the Columbia Gorge.”

Kurt Conger, Northern Wasco PUD, asks for the monthly variability instead of annual data. Conger agrees with Huetten on needing monthly numbers to dovetail into the hydro variability. Charles answers that she showed annual wind shapes for the Columbia Basin and Eastern Montana at the last meeting. Steven Simmons comments that they show a comparison from region to region.

Tom Haymaker, Clark County PUD, asks if the model this will feed into will be a monthly, yearly or hourly model. Simmons responded that Aurora is an hourly model and the RPM is more of a quasi-hourly model. Tom Haymaker explains that, “For our wind PPA we have, we get an average energy and capacity factor on a percentile bases, the median generation is 4%. So half the time it’s generating 0 and the other half it’s up to the capacity factor 30%. I don’t know if that has any bearing on the granularity of your studies. I think you might want to look at the median generation as well as the capacity factor.”

Tom Eckman answers that the Council is using them for different purposes, sometimes its the annual energy output we care about and in some cases capacity. We’re looking at load duration curves for capacity value and right now it’s about 4% for loss of load probability. Not a huge expected contribution.

Keith Knitter, Grant County PUD, asks if the Council is leaning towards the Sixth Plan’s number for new wind or the all wind? Charles answers that it’s for the new wind reference plants.

Cameron Yourkowski comments that the numbers from the Gorge area look correct to him. He agrees that taking a closer look at the Palouse area might be worthwhile. But the Puget Sound Energy IRP for that area is 34% capacity factor. He then raises a question about the data behind Montana and Idaho because, “they look low to me.”

Charles comments that in the third table most of the Idaho projects come from Southern Idaho. Yourkowski asks if it was actual data and Charles replies that it was. Yourkowski asks if there were curtailment issues for Idaho. Yourkowski comments that that may be a factor there. Rick Sterling, Idaho

PUC, says that they don't have any curtailments for the past year and the utility doesn't have the ability to curtail any of those. Therefore curtailment would not be reflected in any numbers.

Yourkowski asks Sterling for comment, "do you think that's a good capacity factor number?" Sterling answers, "I've never done enough analysis to see if it should be 28 or 30. All I can say is that they are in the right ball park." Yourkowski asks about Montana. Charles says it's projects from all of Montana. Yourkowski says that he has seen IRPs that are at 41% capacity factor for Montana using the Judith Gap data. His understanding is that Spion Kop data should be higher.

Charles asks if the 38% from the Sixth Plan is too low for Montana. Yourkowski answers that they are seeing numbers in Puget IRP for 41% and we think new information would be as high as 45%.

Charles asks for other comments. Kurt Conger asked if those were expected or actual numbers? Yourkowski says that he thinks they will get numbers from Spion Kop to support that. For Judith Gap the numbers are existing. Conger asks if equipment efficiency improved or are there better resources out there. Yourkowski answers, "better resource."

Steven Simmons asks for the location of that resource. Tom Kaiserski, Montana PSC, answers that it is just east of Great Falls about 100 miles north of Judith Gap.

Charles asks Brian DeKeip, NW Power and Conservation Council, and Tom Kaiserski, Montana PSC, for input on the Montana capacity factors. Kaiserski answers "I think Yourkowski is right on. My numbers are anecdotal but Judith Gap is north of 40% and Spion Kop is good too, greater than 40%. So based on that 35% seems low."

DeKeip adds that it all depends on the location. If you're in the Judith basin you're going to get high capacity factors. Move away and it will drop.

Charles sums up that if they are going to use the Sixth Plan numbers then Montana should recalibrate up a few percentage points. She points out the numbers shown here are averages not best case scenarios.

Paul Dockery, Clatskanie PUD, asks two questions, "will these reference plants have locations so you can have costs based on the distances to an existing transmission line? And are you going to pick a technology?"

Charles answers that the wind technology selected this go around is generic but that is open for discussion. For cost this time around I haven't chosen specific locations but will do that in the next step. We will have more than one reference plant because wind is so variable that it makes sense.

Dockery proposes selecting a turbine technology and then getting a production curve from the manufacturer. He suggests comparing that number to the wind resource at a specific location because

he agrees with Yourkowski that 38% in Montana seems really low. "Using historic averages for new development does not seem like a good methodology to me," he says.

Tom Eckman asks how far back would you go? Dockery answers "I would not use historic data." Eckman asks "what if we were using the empirical data for production?" Dockery says he would use the GE power curve and run it against where ever your reference plant is; either an NREL map or historic data at that location. "Run calculations from there to get an empirically founded capacity factor but I don't think using historic data for a wind turbine will get you to the right answer."

In conclusion, Charles says that along with specifying technology, she will pull out new projects from Palouse and later. Charles will have revised capacity factors next time. She will increase numbers in Central and Eastern Montana and the Columbia Basin as well.

Dave LeVee, Pwrcast, comments about the volatility of wind and wants it modeled correctly even down to an hourly basis. "It speaks to the direction and knowledge on the demand/response side of things which complements wind's inherent volatility. I'm very interested in how that volatility is modeled all the way to shape curves and how that changes over time." Charles will potentially have data speaking to that issue next time.

Updated Definitions

Gillian Charles discusses updated definitions and brings some to the GRAC's attention. Price year for the draft Seventh Plan is 2015. Year dollars is 2012 dollars. Construction lead time has changed. The last Plan had three phases. Now there are two phases for the purposes of the new Regional Portfolio Model (RPM). The two phases are planning & development and construction.

Keith Knitter, Grant County PUD, asks why the Council chose 2012 dollars for the year dollars definition. Steven Simmons answers that some of the analysis has already been started but assures that the dollars will be normalized. Knitter injects that a report coming out in 2015 with 2012 dollars seems antiquated. Steve Simmons answers that it will be easy to convert back and forth and the vintage will be 2015. Tom Eckman explains that this is one of the problems with having an extended development period. Keith Knitter comments that you have to make a lot of assumptions on escalation rates to bring it to current dollars

Zack Yanez, Snohomish PUD, asks, "Do you look at scenarios with different escalation rates to see how that affects the risk of the portfolio? This might be more of an RPM question." Simmons answers, "But there will be in the RPM an ability to stochastically look at resource cost through a 20 year planning horizon" Simmons continues. "RPM can layer on different escalations. There will be stochastic analysis around the capital cost." Tom Eckman calls for input on what that range and distribution should be, stating, "It's an input parameter that is put into the model. If you have wisdom about the range and distribution that would be great."

David Nightingale, WA Utilities & Transportation Commission, questions a 30-month construction lead time for wind, feeling that it is too long and stating he's seen construction completed in two years. Charles answers that she's seen 22 months but the Council is counting from the equipment order date which is usually 6 months before construction begins. Nightingale points out that equipment is improved and people are better at installing it. Jeff King, J.C. King and Associates, states, "Construction time starts at the point when big money is committed. That's what the portfolio model is about. So a lead time of six months ahead of actual groundbreaking is included in the 30 months."

Paul Dockery, Clatskanie PUD, comments that 20 months is a better number for construction from turbine order to turbine running. However he admits that he worked in the Mid-West where conditions are different. Jeff King says the 30-month number is old, dating from the Fifth Power Plan. Dockery continues by commenting on the economic life of the project. He feels that 20 years is too short and 30 years is more appropriate for a new plant.

Charles backs up to briefly explain the slide on recent wind projects in the PNW, emphasizing the technology portion including vendor, turbine size and rotor diameter.

Preliminary Reference Plant

Gillian Charles outlines the preliminary reference plant. She explains it's a 40 unit, 2.5 megawatt per turbine wind farm with a 100 megawatt lifecycle average. She couldn't find a good source for what the degradation of wind might be. "I assumed a 0% derate over time but this is based on insufficient information." She explains that the economic life of 20 years is based on the Sixth Plan and admits that it sounds like that's too short based on today's conversation. The construction lead time is from the Fifth Plan so it needs to be addressed again.

James Gall, Avista, comments that from his Palouse experience the time he signed the PPA till the generators were on line was 17 months and as far as economic life he signed a 30 year PPA. However, the owner thought that after 20 years, reliability and degradation will be undetermined.

Cameron Yourkowski, Renewable NW, asks what the relationship is between the degradation concept and the fixed O&M cost? Charles responds that degradation has to do with what we are putting into the MicroFin financial model. "Right now I'm putting in 100 megawatts," she says, "There will be a lower lifetime average with degradation." Yourkowski asks if the O&M costs could in theory cover degradation and keep quality up.

Jeff King answers that it comes into O&M two ways; (1) routine labor and maintenance materials, and unscheduled maintenance and items that could be capitalized but are included in fixed O&M. So we try to capture all of the O&M costs over the economic life of the plant when we estimate a fixed and variable O&M. (2) The other way this bears on O&M is the divisor for fixed O&M which is a dollar per kilowatt figure – the same as capital cost. It's intended to be the kilowatt rating of the plant over economic life. He then uses gas turbines as an example. "Gas turbines go downhill they get dirty and

worn and major maintenance brings them up, but not quite to what they were initially rated at. So there's a sawtooth effect. We cut through that to create a lifetime average. With wind turbines we haven't done that in the past. We assume that their initial rating is what they are for their entire life." Jeff King continues. There's some suggestion in the LBNL literature that there may be some degradation to older projects, but we don't have great information on that. So that's the question Charles is pitching. Should we make an assumption and what should it be? In gas turbines its 2-2.5% derate.

Tom Haymaker, Clark PUD, asks if this is a rule of thumb as he has a 17-year-old combustion turbine that is producing higher level now than when first commissioned.

Jeff King , says there's literature from vendors saying the 2-2.5% degradation is to be expected in gas turbines. Haymaker suspects that improved process and controls may be the reason. King responds that with gas turbines a prime mover can be replaced and in one sense that is the end of economic life. James Gall, Avista, adds that he's had improved capacity in the Coyote Springs plant as well. We do see degradation until you do maintenance.

Charles sums up and says there is good information for gas plants but asks is there any for wind? Does a 0% derate sound right? The GRAC agrees that a 0% derate sounds right.

Charles then asks if an economic life of 25 years sounds realistic. Rick Sterling, Idaho PUC, says that nearly all Idaho wind projects have been under PURPA and because of that the contract length is limited to 20 years. The real economic life may be 25-30 years but in Idaho a 20-year life is assumed. Fred Huette, NW Energy Collation, states that based on California experience much equipment will be replaced in 20 years as better technology comes along. But he bets that real life is at least 25 years. Robert Brown, Portland General Electric, states that PGE assumes 27 years for modeling. David Nightingale asks what that number is based on. Brown responds, "Engineering and plant accounting input."

Paul Dockery, Clatskanie PUD, asks why the Council chose GE over Siemens. Charles answers that they went with the generic and GE had 90% of market share in 2013 (nationally). Dockery states that GE has smaller size technology in the 1.5-1.7 range and would either use those numbers or go with Siemens which has a 2.5 technology.

Estimating Capital Cost Assumptions and Normalizations.

Gillian Charles explains the methodology used to develop estimates. They gather available plant data from built and preconstruction projects and generic reports. They then normalize data to Seventh Plan reference plants and finally the team looks for outliers and trends. Based on this work they estimate capital costs and forecast a 20-year trend line.

Estimating Escalation and Hi/Lo Bound For RPM

Gillian Charles explains the escalation and hi/low bound for RPM. She explains the purpose high/low bound on capital costs, essentially a plus and minus percentage off of the capital cost in the plant year of 2015 to project future costs. The intent is to capture the majority of project costs within that bound.

Kathleen Newman, OREP, asks, "Would the probability be a normal curve?" Tom Eckman says the GRAC is able to provide input on that.

Preliminary Capital Cost of Wind

Gillian Charles explains the information that went into the chart emphasizing which data points are outliers and which are heavily weighted. She notes that they chose 30% above and 30% below for the hi/lo bounds. Cameron Yourkowski, Renewable NW, asks if the CEC report is for the West or California only. Charles says it was California only. Yourkowski suggests that the high point looks like an outlier. Charles agrees, noting that it was discarded. Jeff King looked at O&M costs for a variety of technologies and he admits that the CEC report tends to run high compared to other sources.

Greg Mendonca, PNGC Power, asks about the 30% hi/lo bounds, thinking that the pre-construction and as-built lines are tighter. He suggests that if the 30% is applied it would be too high or too low. Charles answers that it was a conservative ball park figure but could be brought down to 25%. Jeff King agrees that it could be brought down.

Ehud Abadi, BPA, asks, "Does LBNL put out trends like this?" Charles answers that they don't have a forward trend but notes uncertainty on future price costs. The LBNL's historic trends are based on national averages, not the PNW region. However, the overall trend is there, but perhaps not at the rate we're proposing.

Zack Yanez, Snohomish PUD, questions using different rates for different technologies and resources. Steven Simmons answers that more mature technologies have more predictable data. Yanez asks if wind technology is that much less mature than thermals. Charles answers that thermals have an even wider proposed hi/lo bound. Yanez comments that he doesn't see the benefit in using different hi/lo bounds for different resources.

Tom Eckman explains that each resource has different components that are driven by different markets i.e. copper, steel, graphite. There are two parts to this, the range itself and the distribution within the range. The distribution within the range is more interesting than the range itself.

Zack Yanez, restates the question, "are you trying to test exposure to changes in capital costs?" Tom Eckman clarifies that they are testing for capital cost risk. Yanez asks if there is a good base study. Eckman says they don't all line up around a central tendency which suggests variance. We know there's variance, but we want to represent an average, a range, but if there's a skew to the range that's what we are trying to know. That's the critical piece.

Yanez continues, saying that providing variance that isn't based on significant real data is making up numbers across different resources. He questions what the Council gains from that. Steven Simmons comments that they are gaining uncertainty because we don't know what will happen over 20 years, so we need to add that uncertainty around a given expectation. Tom Eckman adds that the Council has

empirical project costs ranging from \$200-\$400 range in dollars per KW in the last experience. That's evidence to me that a single number wouldn't work.

Sibyl Geiselman, EWEB, asks what types of variances the Council is trying to capture with this range? Are they locational differences? Financing costs? Siting issues? Or additional transmission costs at sites? She then asks if there is other modeling to capture known locational pricing differences. Charles responds that these are estimated around market factors as this is a generic reference plant. She notes that some factors for recent swings in wind prices are the materials and in 2005 with the onset of a lot of state renewable portfolio standards, demand went up and it became a seller's market. She notes that with this information you could make the case that we should have specific costs and ranges to different resources.

Tom Eckman notes that the transmission and capacity show up separately and Steven Simmons adds that wind does not have a fuel price like gas plants.

Cameron Yourkowski, Renewable NW, asks if there are enough robust data points in the chart to generate data. Charles answers that she thinks it's a good representation, citing data from California and the PNW.

Paul Dockery, Clatskanie, brings the discussion to the DOE line in the chart asking if it was published from historic national data. Charles confirms this but notes that it was with an estimate for 2014. Dockery notes that developing wind in the PNW in 2010 cost \$300 above national average. In 2012 it was \$500 above national average. However, he feels the 2014 estimate of \$600 above national average is too high as turbine prices should come down he thinks it should stay at \$500.

Charles notes that the DOE has other charts based on regional breakouts and that the West is always significantly higher than the rest of the US. Fred Huette, NW Energy Coalition, notes that the material cost is tied to national market but other factors like the dispersion of types of wind, other costs such as California's cost of compliance might factor in. "My gut says this will go lower but I'm not shocked by these numbers," he says.

Preliminary Capital Cost and Escalation Estimate of Wind

Gillian Charles explains the slide drawing the GRAC's attention to the capital cost escalation of -0.5% annually after 2015 with a flat rate each year. She questions whether this is an appropriate estimate of future capital costs as the future seems uncertain based on recent reports. She suggests we could leave it at 0%.

Greg Mendoca, PNGC Power, asks if the recent seller's market and RPS costs are a primary driver in that number. Charles answers yes, but it is one of many factors driving the line. Mendonca agrees that leaving the number at 0% is appropriate.

Dave Nightingale, WA Utilities and Transportation Commission, says the level of RPS hasn't been reached in Oregon and Washington. We don't know what 2020 will look like. We should consider demand driving prices up for the next plan.

Tom Eckman reminds the GRAC that 111(b) and 111(d) will change the national landscape. Nightingale feels that people will not be as progressive as the West Coast in the life of this plan. Eckman states that they are looking for resources through 2035 so it would be appropriate to look that far out.

Greg Mendoca, PNGC, states that a de-escalation rate of -.5% may not be appropriate

Tom Haymaker, Clark PUD, discusses 111(d) saying legislators look at it in a static environment and that it might cause economic downturn. There are lots of open variables out there and 111(d) is not set in stone.

Cameron Yourkowski, Renewable NW, states that he doesn't disagree with how RPS can affect the market but sees a very competitive market driven by 111(d), coal replacement, competition with natural gas prices and technology improvements of wind which makes the de-escalator fair.

Council Plant O&M Costs

Gillian Charles explains Jeff King's work on estimating O&M costs. Zack Yanez asks if the O&M cost includes wind integration costs. Charles answers that it doesn't. Cameron Yourkowski, Renewable NW, adds that the WECC E3 study came out to \$30 a year and Puget came out to \$27. Charles asks for more comments via email.

Financial Incentives

Due to the future uncertainty of financial incentives such as the Production Tax Credit (PTC) and the Investment Tax Credit (ITC), Charles states that the current proposal is to not include financial incentives for wind for the draft Seventh Plan. Rob Petty, BPA, asks if there was a way to model some uncertainty around that or not. Charles and Tom Eckman answer yes it's possible to encompass that through scenarios within a range in costs. Steven Simmons agrees that there is a way to isolate on incentives in the new version of the RPM.

Preliminary Levelized Cost of Wind/Next Steps

This information was created using 2012 dollars, 2015 price year and IOU financing. It's a preliminary draft look at levelized costs and there are two main grid locations local to Eastern Washington/Oregon and Central Montana. Charles broke them out for comparison purposes.

Charles will bring wind back to the GRAC with refinements based on input, along with updated transmission estimates.

Zack Yanez asks about Montana wind model transmission costs. Is it for energy delivered to Washington State in real time? Will it count toward RPS in Washington or be purely an energy replacement resource? If it's modeled one way it wouldn't count as a renewable compliance. But I'm not sure. Steven Simmons asks that notes on the topic be sent to Gillian Charles.

Sibyl Geiselman, EWEB, asks where wind integration costs are captured. Steven Simmons says they are captured in transmission.

2014 Wholesale Electric Price Forecast

Steven Simmons

Simmons explains slides 1-6 noting that a full report on the updated wholesale electric price forecast will come later in the year. He familiarizes the GRAC with the forecast approach using the AURORA Model. He points to important variables that have been updated like demand, fuel prices, transmission issues and greenhouse gas policies, and the fuel price forecast, but noted that there were no significant changes in any of the variables since the last forecast.

Electric Price Forecast Range for Mid-C bounded by low and high fuel prices

Steven Simmons explains the annual forecast range stating that they are bound by high and low fuel prices; they are driven mostly by the natural gas price forecast. Greg Mendonca, PNGC Power, asks if he sees increased volatility throughout the year. Simmons says it's relatively the same month to month because it's the forecast based off of the mid-ranges of all the variables. Dave Nightingale, Washington Utilities and Transportation Commission, asks if it's annual average price. Simmons says yes. Villamor Gamponia, Puget Sound Energy, asks what's causing the slight shift in price from 2020-2021. Simmons answers that coal retirement and a bump in natural gas price is the cause.

Preliminary Assumptions for Natural Gas Peaking Technologies (Revisited)

Gillian Charles and Steven Simmons

Gillian Charles reviews topics from the last meeting and points to today's discussion of revisiting reference plants and updating capital cost estimates. Staff will introduce fixed and variable O&M estimates and introduce levelized cost estimates. She reviews reference plants. She notes that the California Energy Commission data will be included as well as the recent NERA reports on NY ISO. Charles notes some changes since the last GRAC meeting, including a decrease in capital cost estimates for frame and aero. She added a hi/lo bound percentage and notes that the future is uncertain so they are assuming a conservative 0.5% annual cost reduction due to technology improvements over time.

Preliminary Reference Plant – Frame GT

Gillian Charles explains the slide noting that many of the points on it were addressed earlier in the day. Fred Huette, NW Energy Coalition asks is there much dispersion on the heat rate, Charles answers that they are pretty close. Huette asks if there is a difference when you look at field data. Charles says this plant is comparable. Steven Simmons agrees that the five existing manufacturers are close to each other.

Preliminary Draft 7P Capital Cost Estimate for Frame GT

Gillian Charles explains the data that make up the capital cost assumptions.

Fred Huette, NW Energy Coalition asks if they were looking at the WECC assumptions. Charles answers that they looked at the E3 WECC report, which followed a similar methodology to the one the Council does in developing capital cost assumptions. She notes they don't have a lot of data points for actual frame projects. She explains the draft Seventh Plan estimate line starting in 2010 and says that disparity between the Sixth Plan final estimate is caused by advancement in technology - the Sixth Plan used an E Class as its reference plant. She is open to fit it into one line if the GRAC agrees. She explains the hi/low bounds of high 35%/low 25% along with a capital cost of \$800 and calls for reaction.

Kurt Conger, Northern Wasco Co PUD, states that the \$800 looks consistent. He asks, "Did you adjust the Gas Turbine World number for balance of plant costs?" Charles answers yes. Russ Schneider, Flathead Cooperative, states that based on the 30% hi/30% low you had for wind the 35%/25% looks odd based on consistency. Charles answers that it's an assumption that is technology-specific and that most of the peaking units have an assumed 35-25%. The wind technology is based on data we've seen, past and future trends, the 30 up and down seemed appropriate.

Ehud Abadi, BPA, says there are aspects which sets this data apart from each other. More than just the normalizing for balance of plant that Kurt Conger brought up. He suggests describing in more detail the variability of sources plotted, why some are outliers and others given more weight, and talk about how that's driving the 35/25%. Charles answers that that a lot of the data to build the chart is compiled in a big excel spreadsheet that would explain all of the normalizations and characteristics of each data point. If she plotted directly the points from the sources, the points would be all over the place. Kurt Conger brings up the 35/25% range concluding that each of us can come to our own conclusion within those bounds.

Sibyl Geiselman, EWEB, states that the data shows an increasing price trend with a decreasing heat rate assumption. She wonders what the underlying heat rate decline curve looks like, thinking maybe there's no data to warrant capital cost decline but instead heat rate improvements over time. Jeff King answers that the Sixth Plan had a heat rate downward trend of .5% per year as well. He says that they looked at it for the Fifth Plan very intensely. The heat rate information bounced around a lot but it did trend downward to about .5% a year. The theoretical potential heat rate from a study in the 1990s was quite a bit higher than that of machines currently in the market, so it didn't seem unreasonable to think that it would continue to drop over time.

Geiselman thanks the staff for clarifying and then asks how they warrant the downward trend in prices as it seems like they are ignoring data trends.

Charles answers the 2010 NERA NY ISO was weighted heavily, while the Marsh Landing report was treated as an outlier. There was definitely a price increase in 2008 that wasn't forecast in the Sixth Plan so that's why there's a disconnect. She speculates that perhaps she should draw the lines together.

Jeff King explains what was happening at the time of the Sixth Plan. We closed the Sixth Power Plan three months after the economic events of 2008 struck. We had information that prices would drop but that trend didn't continue. I'm wondering if some of the 2010-11 high prices result from projects that started in 2008." Steven Simmons agrees that it might. However, Charles says that the data points are plotted based on the vintage of the estimate, not when the project went on line.

Charles calls for feedback. She concludes that the \$800 overnight capital cost might be revisited again. She also points to a box in the chart discussing the proposed fixed and variable O&M costs stating that the numbers are new since the last time we looked at peakers. She calls attention to the difference between the Sixth Plan estimate and the proposed draft Seventh Plan estimate on the variable O&M assumption, which was based on Jeff King's research. King said the difference is because O&M data is poorly documented so you have to infer. It appears that variable O&M costs are influenced by vendor contracts. More and more turbines are operated and maintained under contract with a vendor. So the cost is tied to operating hours or starts. Owners report that out as variable costs.

Kurt Conger asks, does your model include or exclude start costs? Jeff King answers that the only model that explicitly models start costs is Aurora. In the past start costs haven't been broken out. We looked at the price forecast for the Aurora model and how it was operating peaking units in the NW over the next 10 years, we looked at average number of starts and average capacity factor and tried to tweak fixed and variable costs to be consistent with that. So the best way to treat start costs in this case is to fold them into the variable O&M cost assumption.

Conger says your variable O&M cost looks high but if you're averaging start costs in then it makes sense. Ehud Abadi, BPA, asks if that was done for the Sixth Plan. King replies that it wasn't.

Dave Nightingale looks to capacity factor slide (10) and asks if this is the range you're seeing and which years did you look at. Charles jumps to the **Preliminary Levelized Cost Frame GT** slide. She explains the data and the reasons for selecting the capacity factors for this chart – 46% was used in the Sixth Plan and was likely used to compare the peaker to a combined cycle combustion turbine, 10% is probably more representative of actual projects in the PNW, and 25% was selected as a mid-point. Nightingale wants to know how many years of data she used. Charles responded that actual data from existing plants suggests even lower capacity factors, but says she can pull the data for next time. Jeff King says the Aurora run pushes 6-8% capacity factor. It was going up over time because of dispatching hour by hour. Charles discusses the assumptions section of the chart and stresses that the emission costs were not added at this time.

Zach Yanez asks if the levelized costs are just used for comparison purposes. Steve Simmons says the RPM does use a fixed portion of levelized costs. Yanez says the capacity factor doesn't matter right? Simmons answers yes. Yanez notes that the vertical axis is \$/kW even though this is a typo he is interested in data expressed this way. Yanez thinks it would be easier to see and make sense. Tom Haymaker, Clark, would like to see this too.

Preliminary Reference Plant Aero-derivative GT

Gillian Charles explains the slide.

Preliminary Draft 7P Capital Cost Estimate for Aero-derivative GT

Gillian Charles explains the data. Highwood is considered an outlier along with the Pueblo Airport. The hi/lo bounds are 35/25% with -.5% de-escalation starting in 2015. Since the last time the GRAC saw the slide we came down about \$100 based on the CEC report survey data. Tom Haymaker, Clark, asks why the Gas Turbine World costs are consistently low. Steven Simmons says that's a good observation. Charles says we tried to normalize it as best we could, by adding a balance of plant assumption. Haymaker restates that the numbers seem so different. Simmons says it's probably the manufacturers sending their best case scenarios.

Preliminary Reference Plant-Aero-derivative GT (2)

Gillian Charles explains the data. She notes that the fixed O&M estimate in the Sixth Power Plan is about half the assumption proposed for the draft Seventh Power Plan. Jeff King responds that we don't have a good rationale for that increase other than the predominance of the information suggests we were underestimating the fixed costs fairly significantly. Kurt Conger notes that both those numbers look high. I'll send other consultant's reports to you. Charles says that would be great.

Preliminary Levelized Cost –Aero-derivative GT (1, 2)

Gillian Charles explains the data saying it's the same assumptions as before. She moves through the next slide with no comment. The next chart of levelized costs shows what the cost may look like using the Sixth Plan's CO2 cost estimates, with a deferred start date to 2015.

Preliminary Reference Plant-Intercooled GT

Gillian Charles explains the slide to no comment.

Preliminary Draft 7P Capital Cost Estimate for Intercooled GT

Gillian Charles explains the slide. Outliers include Haines in Central LA. She points out that there is no good data for NW as there are no plants here; however comparison could be found in Texas and New Mexico. She notes the NERA NY ISO estimate dropped from 1200 in 2010 to 1100 in 2013. Ehud Abadi asks didn't they finish CPV Sentinel plant? Charles says yes but the data point is representative of the preconstruction cost estimate.

Jeff King points out that we could be looking at the declining cost of construction as this model was introduced in 2004. So there would be a reduction in manufacturing costs and efficiencies of construction.

Preliminary Reference Plant-Intercooled GT (2)

Gillian Charles explains the data. She points to the fixed and variable O&M says that it's close to the Sixth Plan, although a little higher on both. She asks for feedback.

Fred Huette mentions that fixed and variable O&M didn't change much from the Sixth Plan estimates for the intercooled but it did for the others. They are big machines with some differences and some similarities. Should we expect such a difference between the classes?

Jeff King answers that assessing fixed and variable cost data can be problematic because of different assumptions, for example property taxes. They are an O&M cost because you pay them every year but they are a capital related cost as well. Sometimes the estimates include property tax, sometimes they don't. Property tax, if included, can double the overall O&M estimate - but most of the documentation for these reports and data points does not specify what is included in the cost estimate. In addition, local tax rates vary as well. That's why we like the NY ISO document because they itemize everything - we use the Albany and Syracuse cases because they are a bit more representative of the PNW situation. Another reason assessing O&M estimates is difficult is that the O&M contracts are variable. Sometimes just the cost shows up with no owner's costs like administration, permits and maintenance. Sometimes plants include SCR so there's a catalyst replacement or ammonia purchase cost that's not mentioned so it's very difficult to normalize. That's why we closely weight the NY ISO estimates and the Port Westward submittals to the OPUC.

Huette says you have two choices. You could just say what the O&M is across all the classes. I wouldn't argue you do that. Or you probably have to go with the data you have and understand why you have the differences. Just understand why you have these differences. Jeff King talks about the difficulties of the frame units O&M estimates. Those machines don't have catalyst replacements or ammonia purchases like other peakers do so that is not accounted for in the O&M estimates.

Greg Mendoca, PNGC Power offered the general comment that the variations seem so much larger that it's difficult to comment without direct experience. The charts show 100% variation within the year so that's why I'm being quiet.

Preliminary Levelized Cost-Intercooled GT

Gillian Charles discusses the slide which assumes that no emissions costs were added at this time. They are pending the environmental methodology.

Reciprocating Engines for Electric Power Generation

Steven Simmons discusses the advantages of reciprocating engines including their quick starts, their ability to maintain output at increasing elevations and their minimal water use.

Normalized Capital Costs for Reciprocating Engine Technologies with High and Low Band

Steve Simmons discusses the costs and says they are reference sources. He stresses Port Westward II high and low cost estimates. He notes the E3 data point. He says the NY project was normalized for NW labor but still runs high. The capital cost is \$1300 per kilowatt with a hi/lo of 18/15%. He defines WADE as World Alliance for Decentralized Energy and says he went through their 2007 report.

Preliminary Reference Plant- Gas-Fired Reciprocating Engine

Steve Simmons points to the data, noting that Wärtsilä is the technology selected. He says the fixed O&M is a little less than Sixth Plan, but we're adding variable O&M in addition this time.

Fred Huette, NW Energy Coalition, questions the capacity factor of "to be determined". We're looking at three projects Excell, PGE and Humbolt they are somewhat different in their purpose. So I'm not sure if you'll be able to plug in the data because it's situation dependent. Steve Simmons acknowledges the point

Kurt Conger, Northern Wasco PUD, asks, "These plants are at the top of your supply curve. Does your model not produce the capacity factor based on the simulation you run?" Simmons yes it does. It's the fixed portion of the levelized cost. The capacity factor is what the model is going to run at. Conger asks, so the capacity factors could be very high for dry years and for wet years down near the bottom? Simmons answers, "Right if you have a lot of dry years you could pick a unit that has a better heat rate because it would be running more." Huette interjects that the last two years were completely driven by hydro and gas ran very little even though gas prices were low. Now gas is high but is running more because of the low hydro year so it's not the cost of gas that dictates it but the availability of hydro.

Tom Haymaker brings up the wholesale power price forecasts for Mid-C, asking if they are for 2012 dollars across the years. Simmons says "yes real 2012 dollars." Haymaker asks if the Council looked what levelized for 100 megawatts of flat power would be across that time period. Simmons says no. Haymaker says those numbers might tell us something. Simmons says they will be low. Haymaker says when you do the wholesale power price forecast you are assuming new units added, right? Simmons says "correct." Haymaker points out that it's not a true variable cost. Simmons agrees and says there are some fixed costs in the model. Tom Eckman states that it still stays pretty low. Haymaker agrees.

Simmons continues, discussing the slide showing the comparison between the levelized costs of the gas peakers. He says they are similar. Capital costs are higher for recip, but the fuel cost component is lower due to the better heat rates for recip. He states that the aero O&M portion doubled since the Sixth Plan.

For next steps we will take feedback and refine estimates, and incorporate the environmental methodology once it is determined. Kathleen Newman, OREP, asks about water cooled vs. air cooled technology. Simmons says that it's on the combined cycle. Zach Yanez asks, the RPM doesn't have the granularity to distinguish within hour benefits of the peakers, correct? Tom Eckman says correct. Yanez then asks if there is a way to look at a given year or a given hour. He feels that would be a way to back into a value adder for these different thermals, like an out of model adjustment. Tom Eckman states that it is on the work plan as a way to develop a method to deal with capacity and flexibly inside the modeling process, through RPM or side calculation. We want to identify the need and the benefit stream to providing an answer to that need. So it's on the list of to dos.

Yanez then asks that as far as environmental methodology for wind would you consider additional dispatch of thermal plants to integrate them. Eckman answers that if there's a cost to integration and

we include an emissions value that it would show up in whatever run time we have for integration. Yanez says he does not envy the work the Council is doing and thanks the Council for chasing deep rabbit holes.

Financial Overviews and Profiles

Steven Simmons

Simmons explains he will go over assumptions on the MicroFin model which was used to calculate levelized costs. He will go through the model's assumptions.

Supply Side Cost Estimation

Simmons explains that the GRAC provides an estimate of capital costs and operating characteristics which is fed into the MicroFin model to provide the cost of the capital. He also points to the fuel price forecasts. MicroFin then generates the fixed levelized cost at \$/kW-yr and the full levelized cost of energy (LCOE) -\$/MWh. The fixed portion is what gets fed into the RPM and based on the future that it is seeing as far as natural gas prices, demand, capital cost, etc. it will decide essentially how to dispatch and what resources to add.

MicroFin

Simmons reviews MicroFin. He points to the three financial sponsor options: Muni/PUD, IOU, and IPP. He then points out the key assumption differences among sponsor types stating that Muni/PUD have advantages in tax rates. He also points to debt rates and service periods along with equity return rates and service periods. The table on slide 5 breaks down the MicroFin financials key assumptions across the three financial sponsor options.

LCOE Illustration of Advanced CCCT

Simmons explains the data of the example. He comments that a big cost component for a CCCT is the cost of fuel.

Kurt Conger, Northern Wasco PUD, comments that he downloaded the Levelized Cost Energy Primer from the website and it looks like energy production is also discounted. Is that right? Simmons says not in MicroFin. Tom Eckman agrees stating that it discounts the money and not the physical units. Ehud Abadi, BPA, states that he was under the impression that we do discount the megawatt hours and notes that this is an ongoing conversation at BPA. Dave Nightingale, Washington Utilities and Transportation Commission, states that discounting energy doesn't make any sense. Eckman states that both MicroFin and ProCost don't discount kilowatt hours or emissions. Conger calls for a revised primer. Simmons agrees that it's misleading. Eckman agrees that it is not how the models work.

Simmons continues noting that in the Sixth Plan the IOU was assumed for the sponsors for all of the levelized cost calculations for consistency. He also notes that in the PNW most gas and wind was developed by IOUs. He continues with around the country most solar was IPP developed. He points out the difference between the IOU and IPP, stating that the levelized costs come out very similar. Ehud

Abadi, BPA, asks if we know what we're basing the leverage rate on at this point? Simmons answers that it is similar to the Sixth Plan and it seems consistent to other reports I've seen.

Time Value Considerations for Economic Comparability

Dave LeVee, PwrCast Inc.

LeVee reiterates that in the Sixth Plan a single source of capital was used. He plans to go over that assumption and question if there should be changes for the next Plan.

LeVee stresses that he looks at cost effective energy from a customer's viewpoint. He looks for the best value for customers and that value includes price and reliability.

The current Plan looks at a "least-cost perspective," LeVee states, "That's not the whole story."

Comparison of Alternatives

LeVee stresses that he wants an apples to apples comparability between alternatives including capital and operating costs. He stresses that if you are not careful in measuring revenue requirement costs you bias the results. In that vein, it's not appropriate to just look at financial differences between entities in the region. Those differences often exist because risk has been shifted from the investors to the customers or some other entity and it has the appearance of a lower cost.

Financial Differences among Regional Constituents.

LeVee explains the differences between IOUs, Public Ownership and IPPs. He also talks of off balance sheet financing. He notes there are ways to shift risk from the company giving the appearance of reduced risk which effects cost of financing. He notes that the risk comes back to the balance sheet in one way or another.

Entity Cost w/Finance Differences

LeVee discusses the slide. He talks about revenue requirements. For a PPA, it is a take and pay situation allowing the investment to have the assurance of revenues and therefore full debt financing. Public utilities are near 100% debt with a little bit of equity from investors, but a non-tax paying entity. He notes that PPA and public each have a net present value (NPV) of 1.0 times overnight cost. However the IOU, with a 50/50 debt equity ratio, has a NPV of 1.31 times the overnight costs while the market-based IPP, which takes a higher equity and risk position, has a NPV range of 1.5 to 1.4 times overnight cost. He notes that when measuring the different resources each has a different financing cost. If you are using that as an economic measure you are biasing yourself.

What is the Solution?

LeVee says that a market perspective is most pure but hard to measure. It doesn't exist to any degree in the electric industry because of IOUs with regulatory assurance, and munis have an apparent lower cost but the risk has been shifted away. We don't have IPPs that will sell into market. They have a hard time existing because of higher assumed cost even though the consumer is taking a lower risk because they have freedom to choose where to buy their energy or even whether to take it at all. IOUs are probably the best for economic analysis.

Other differences not addressed

LeVee references the slide and moves the conversation forward.

David Nightingale, WUTC, asks if LeVee has done work in quantifiable or non-quantifiable areas. LeVee answers that he has performed utility and non-utility cost of capital risk measurement. He mentions his credentials. He also mentions that he was one of the developers of the Aurora forecasting model.

Jeff King notes that the Council analyzes cost effectiveness through the RPM model. The fixed costs in the RPM have been developed assuming IOU financing in the past. However some may argue that IOUs don't assume all risk, like the gas price risk. On the other hand in the Council's analysis, gas prices are allowed to vary in the RPM model. So that risk is captured in the analysis of cost-effectiveness, along with carbon risk. The other entities don't assume those factors. What are your thoughts? Are we successful in capturing the majority of risk that is present in the industry?

LeVee feels that assessment is accurate and fair. Consumers bear the risk of the market price changing but investors bear the risk of the investment. But I think you've put things in the right buckets and identified consumers risks and investor risks.

Dave LeVee calls for direct comments to be emailed to him for further review and discussion.

Regional Hydropower Potential Scoping Study: UPDATE

Gillian Charles

Objective

Charles reminds the group of the objective of the regional hydropower potential scoping study, which was to hire a consultant to review the vast inventory of recent studies and reports both nationally and regionally. They hope to determine a reasonable assumption of hydropower potential that can be assumed for the Pacific Northwest.

An RFP was released July 18 and proposals were due two weeks later. The Council selected the Northwest Hydroelectric Association (NWEA) with subcontractors from other consulting firms. The final report was completed September 30, however there is an outstanding task concerning the mapping of report results with the Council's environmental protected areas. This part is expected to be completed at the end of October.

As part of the contract the NWEA will present to the GRAC. A two-hour meeting will be scheduled in November for that presentation. After that we will present information to the Council in December and identify next steps.

Tom Haymaker, Clark PUD asks if the study will include incremental capacity and energy or pump storage as well. Charles says it's everything. Haymaker expresses interest in the report.

Discussion of Next GRAC Meetings

Simmons notes that future GRAC meetings will likely be held more frequently from now on due to the compressed nature of the Seventh Power Plan. Doodle polls will be sent out soon to get a schedule in place for the next several meetings. In the meantime, as always feel free to reach out to staff if you have any questions or feedback.

Greg Mendonca, PNGC Power, asks about the Demand Forecast. Tom Eckman says there was a meeting in June where Federal standard impact on future loads was discussed. He notes that there will be thirty new Federal standards in this decade. He points to analysis that came up with about 1000 megawatts of reduced load by 2035.

Steven Simmons and Gillian Charles sum up and thank the group for their feedback.