

Generating Resources Advisory Committee
February 26, 2015
2:00pm – 3:30pm

Meeting Time: 2:00 P.M. to 3:30 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

Steven Simmons	NPCC
Gillian Charles	NPCC
Jeff King	Consultant
Allegra Hodges	BPA

Attendees via Go-To-Meeting

Ashley Bennett	Seattle City Lights
Leanne Bleakney	NPCC
Bear Prairie	IF Power
Dave LeVee	Pwrcast
David Vidaver	California Energy Commission
Elizabeth Osborne	NPCC
James Gall	Avista
Greg Mendonca	PNGC
Elizabeth Hossner	Puget Sound Energy
Jan Lee	NW Hydro Association
Kathleen Newman	Oregonians for Renewable Energy Progress
Keith Knitter	Grant County PUD
Grant Laughter	PacifiCorp
Michael O'Brien	Renewable Northwest
Rebecca O'Neil	PNNL
Greg Nothstein	Washington State Dept of Commerce
Rick Sterling	Idaho PUD
Shirley Lindstrom	NPCC
Stefan Brown	PGE
Alex Swerzbin	
Thad Roth	Energy Trust of OR
Tom Haymaker	Clark PUD

Will Price	EWEB
Dave Nightingale	Washington Utilities and Transportation
Zac Yanez	Snohomish PUD
Megan Decker	Renewable NW

Steven Simmons, NPCC began the meeting. He reviewed the agenda and made introductions. See [presentation](#) for discussion points and analysis.

Renewable Portfolio Standard Analysis

Gillian Charles, NPCC, presented a discussion on the Council's Renewable Portfolio Standard (RPS) analysis and treatment in the Regional Portfolio Model (RPM), along with some specific assumptions being made in the modeling process.

Greg Mendonca, PNGC, asked if Credit States with Surplus Resources for Banking [slide 6] just looked at resources specific to that state. Charles stated that the Eligible Resources generated are allocated to the state in which they have RECs contracted to – oftentimes this is the state in which they are generated. Mendonca asked what the Council assumes for the excess resources. Charles answered that they can be banked by the individual states' banking requirements until they expire. She stated that there is a question about this that comes up later in the presentation.

Mendonca asked if the yellow plaid on Slide 7 includes the 460 MW of utility scale solar PV. Charles stated no, that is primarily about 850 MW of wind RECs with unknown allocations. It is probably safe to assume that a portion of those RECs are going to Oregon, Washington, or Montana – we just don't know how much. In most of these energy sales agreements, there is a 50/50 split of REC ownership between Idaho Power and the developer. Where the RECs go from there is unknown.

Shirley Lindstrom, NPCC, stated that not all of the Idaho projects are a 50/50 split and more goes to the developer. But she is unsure of the breakout. Charles asked for feedback on that.

Keith Knitter, Grant County PUD, suggested that Charles accessed the state records of what would have been achieved to date. He said Washington puts together a yearly report of targets and how many and what types of renewables are reported against it.

Leann Bleakney, NPCC, stated she is watching house bill 2627 in Oregon which incentivizes investment in clean energy and energy efficiency.

Tom Haymaker, Clark PUD, stated that there are provisions in RPS implementation language that is different than the 3, 9 and 15% levels. Charles asked if he is talking about the cost cap provision. Haymaker said yes and stated that in addition there are utilities that are not experiencing load growth – which represents another alternative form of compliance. He says that Clark County PUD has utilized the “no load growth” provision for meeting the RPS requirement. He feels this will have an impact as we move forward. Charles said this was good to know that utilities are potentially facing the cost cap and no load growth alternatives earlier than first thought.

Dave Nightingale, Washington Utilities and Transportation Commission, commented on IOUs and saying they will not be running up against the cost caps for their RPS requirements. He suggested asking Chuck Murray or Glen Blackman for a better estimate for the public side.

Lindstrom again stated that she is not sure if the Idaho recs are 50/50. Rick Sterling, Idaho PUC, stated that large projects which is basically all wind and solar are 50/50.

James Gall, Avista, asked Sterling if the older PURPA wind projects were 50/50. Sterling couldn't answer that as there weren't significant recs until 2005.

Mendonca suggested tapping into the completed BPA analysis for tier one RECs. Charles agreed and asked what he heard from his utilities. He said it plays into his earlier point about RECs that can't be used in Washington. He said that because Oregon has unlimited banking if a single project that is intended to serve Washington RPS but has additional RECs and is also eligible in Oregon then one of the only place to move them is Oregon. Charles said that the current modeling accounts for REC banking in the state but not secondary REC sales. We just assume they expire.

Megan Decker, Renewable NW, stated that there is a voluntary market for RECs and not all RECs end up in the Oregon compliance market.

Zac Yanez, Snohomish PUD, asked about the alternative compliance measure. He feels that his utility is long on RECs now but by the time they need to acquire the next batch they might exceed the 4% cap. He stated that his utility is close to hitting the 4% cost cap.

Gall stated that the numbers don't show the voluntary recs. He wondered if the numbers should be grossed up to show those quantities. Charles asked where you could find that data. Gall stated he's seen it on corporate websites.

Decker stated that NREL has some high level green e-certificate reporting. She feels individual corporate purchasers might be hard to find.

Assume utilities will use banked RECs first, then RECs from current year's generation

Elizabeth Hossner, Puget Sound Energy, stated that she can only bank one year so they use the banked recs first and then go what they can pull for a year. She stated that the incremental hydro cannot be banked and has to be used that year. She states that when modeling for their IRP they look forward for how many recs they need and bank forward. They assume the surplus is sold. In the 2013 IRP they banked until 2022.

Mendonca stated that for the small utilities in the Oregon RPS that would be a good assumptions. Charles asked if the small and medium utilities can bank RECs now, even though they don't fall under compliance until 2025. Mendonca answered that they have been able to bank since 2007.

Gall stated that they are following Puget's banking procedure and appear to be long in the next 20+ years. He says this is mostly through physical compliance.

How to allocate Idaho RECs (that are not specifically under PPAs w/ utilities obligated by RPS)?

Sterling stated that he thinks that some voluntary RECs go to Colorado or California. He is not sure where most end up. He stated it is complicated.

Charles stated that since Washington's IOUs are in such good shape that maybe not accounting for Idaho's unknown RECs isn't a deal breaker. Sterling stated that there are people who do know where they are going but the information is very difficult to track down. He suggested contacting the Center for Resource Solutions or WREGIS.

Yanez stated that if you ignore the Idaho RECs completely, then the region might add resources or purchase RECs before we actually need them. He stated that even if no one is using them they might be available in the future so the next REC expansion might not happen. So from a resource expansion position it might be better to say that the RECs would be available in the future.

Charles asked if it was good enough to identify them in the narrative or should we apply a percentage in the model even if we don't know what that percentage should be. Yanez felt there should be a percentage in the model.

Decker stated that there have been some RECs from PURPA projects that have ended up in compliance reporting that might yield a percentage that would be a good proxy to use. She supports that some percentage should be represented in the model. She feels assuming 50% to the PNW seems high but maybe 25% is more realistic.

Yanez suggested looking at the delta in the model results if you assume all are available and none are available to get a range.

Of the ~460 MW under ESA with IPC, how much can we realistically expect will be built and installed by end of 2016?

Sterling stated that 60 MW of the 460 MW Idaho RECs are actually in Oregon. Of the remaining 400MW, half is being developed by First Wind in partnership with Sun Edison and he expects them to be developed. The other 200 MW is a different developer and he is not sure about their financing but is fairly confident that they will be developed.

He mentioned that there is discussion of another 800-900 MW that might come on line but that is speculative until at least mid-summer.

Future “Achievement” towards RPS – 95% vs. 100%

Nightingale suggested talking to a few utilities instead of coming up with a one size fits all approach. Charles stated that unfortunately the model only accepts one value per state. Nightingale still suggested looking at individual loads. Charles admitted that the large utilities are running into the cost cap, however the difference between 95 and 100% in the model is not that much. Nightingale again suggested contacting Glen Blackman and Chuck Murray for the best estimate.

Haymaker suggested she be careful with wording “achievement” “targets” and “compliance” as utilities may not be hitting the 9% target (in Washington) but are still in compliance using alternative compliance means. Charles agreed and noted that staff will be careful with wording.

What is the current value of a REC?

Gall suggested that for California bucket one recs are closer to \$10/MWh but for bucket three \$1/MWh is more accurate.

Definitions & LCOE

WIND AND SOLAR GENERATION

Simmons presented some additional wind and solar resource analysis assumptions based on various locations and transmission builds.

Nightingale asked about scenarios for southern Oregon wind. Charles stated that they hadn't looked at them for reference plants for the model. Nightingale stated that with four Montana winds, some more realistic than others, the Council should look at at least one southern Oregon one even with the transmission constraints.

Stefan Brown stated that there was a project 3-4 years ago in SE Oregon that tried to connect but had to build a 230 KV line making it economically unviable. Nightingale stated that there are two 230 KV lines there now and there would probably be some curtailment. Simmons stated that the line is fully subscribed.

Charles stated they focused on Montana because the wind resource potential is high (3rd in the US) and we are trying to model diversity. Nightingale still felt that they are focusing too much on Montana and should look at southern Oregon. Simmons stated that between the draft and final they may look at more solar PV in southern Oregon, which would also need additional transmission.

Hossner asked why the Montana wind capital costs are so much lower than the Columbia Basin. Simmons answered that this is on a levelized basis and the Montana capacity factors are better. Charles stated that they assumed a 40% capacity factor for Montana and 32% for the Columbia Gorge.

Nightingale asked for the capacity factor for the solar. Simmons answered 26.2% for southern Idaho. Charles stated that they based this on the PV watts model from NREL and also noted it is in line with the estimates coming out of the energy sales agreements for the ~400 MW under development in Idaho.

Kathleen Newman, Oregonians for Renewable Energy Progress, asked for more information about using the Boardman-Hemingway costs. Simmons answered that because it's a proposed transmission project they were able to find estimates and WECC provided some estimates as well. Newman asked if that put the full cost of such a transmission expansion on solar PV when in reality it might be a shared cost. Simmons answered that it might be shared but it would be a new cost factor to add on. It might not go fully on solar.

Sterling stated that his last solar contract was levelized to \$62 and then subtract \$5-6 for integration so you could do these projects without transmission for \$56-57. Simmons agreed and stated it's a challenge because the levelized costs for modeling purposes are not the same

as a power purchase agreement. He notes they will continue to look at it between the draft and the final.

Mendonca asked about the investment tax credit. Simmons stated it is modeled at 30% through 2016 then dropping to 10%, per the regulations.

Michael O'Brien, Renewable NW, asked about the status of solar technology learning as applied to the levelized cost. Simmons answered that the learning curve was applied to the capital cost. He stated they will look at it again between the draft and final plan.

Yanez brought up wind replacement for Colstrip and asked if the Council will be modeling the most economical way to replace Colstrip without forcing in the wind. Simmons answered that the Council wouldn't force in wind but make the transmission available after retirement.

Simmons concluded the meeting.